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WATERFLOODING AT SIMULATED RESERVOIR CONDITIONS

By

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A THESIS
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The undersigned certify that they have read, and recommend to the Faculty of Graduate studies for acceptance, a thesis entitled WATERFLOOD AT SIMULATED RESERVOIR CONDITIONS submitted by Rajendra K. Agrawal in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

ABSTRACT

Equipment was designed to perform water-oil displacement tests on the core samples at reservoir conditions of temperature and pressure. Once the equipment was built and tested, the effect of core and environment conditions was investigated for a particular rock-crude oil system from northern Alberta.

In order to study the effect of core condition, waterflood tests were run on the preserved cores, the cores were then extracted, and the tests repeated. The tests at both core conditions were run at room condition of temperature and pressure using refined oil as the oil phase. The results indicate that the extracted cores flooded more efficiently than the preserved cores.

In order to study the combined effect of core condition and the test environment, water-oil displacement tests were performed on preserved cores at reservoir conditions of temperature and pressure. Subsequently, the same cores were extracted and tested for water-flood behavior at room temperature and pressure. A recombined sample was used as the oil phase for the reservoir condition tests, whereas refined oil was used for the room condition tests. The results indicate that the extracted cores at room conditions flooded more efficiently than did the preserved cores at reservoir conditions.

After comparing the findings of this work with those of earlier workers, the author feels that, in general, the water-oil displacement behavior of preserved core at reservoir conditions cannot be established from the water-oil displacement behavior of extracted core at room condition.

ACKNOWLEDGEMENTS

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INTRODUCTION

The use of laboratory core analysis test results to assist in the prediction of waterflood reservoir performance is common practice in reservoir engineering. The theoretical validity of such use has been well established (1, 2, 3, 4). Such waterflood tests are normally performed on oil-field cores which have been cleaned and extracted prior to testing. The tests make use of the refined oil as the oil phase and are performed at room temperature with the outflow face being at atmospheric pressure. This procedure has always been subject to question because of the possible influence of test environment and core conditions on the displacement behavior.

Some of the earlier workers (5,6,7,8) have been concerned primarily with the test environment, i.e. whether pressure, temperature and type of oil affect the results. Others (9,10,11) have investigated the effect of core condition, i.e. whether surface characteristics of extracted core are representative of the characteristics of in-situ reservoir rock. The combined effect of test environment and core condition has also been studied (6,11). However, most of these workers (10,12) have pointed out that the effect of core condition and environment condition on water-oil displacement behavior of core samples from different reservoirs is different.

The object of this work was to study the combined effect of test environment and core condition, and the effect of core condition alone on the displacement behavior of a particular rock and crude oil system from northern Alberta.

DEFINITION OF TERMS

Some of the terms, which have been commonly used in this work and need explanation, are defined below.

The "room condition test" refers to a water-oil displacement test carried out at room temperature, with the outflow face at atmospheric pressure using refined oil as the displaced fluid.

The "reservoir condition test" refers to a water-oil displacement test carried out at reservoir conditions of temperature and pressure, using the reservoir fluid as the oil phase. In order to maintain the single phase flow through the core, the outflow face of the core, in this work, was always maintained at a higher pressure than the bubble point pressure of the crude.

"Reservoir oil" refers to a fluid obtained by recombination of the samples of the oil and the gas collected at the wellhead of "HB Union Kaybob S 12-4-62-20" to give a gas-oil ratio of 756 standard cubic feet of gas per barrel of residual oil.

"Fresh core" refers to the core at the wellhead immediately after it has been taken out of the well.

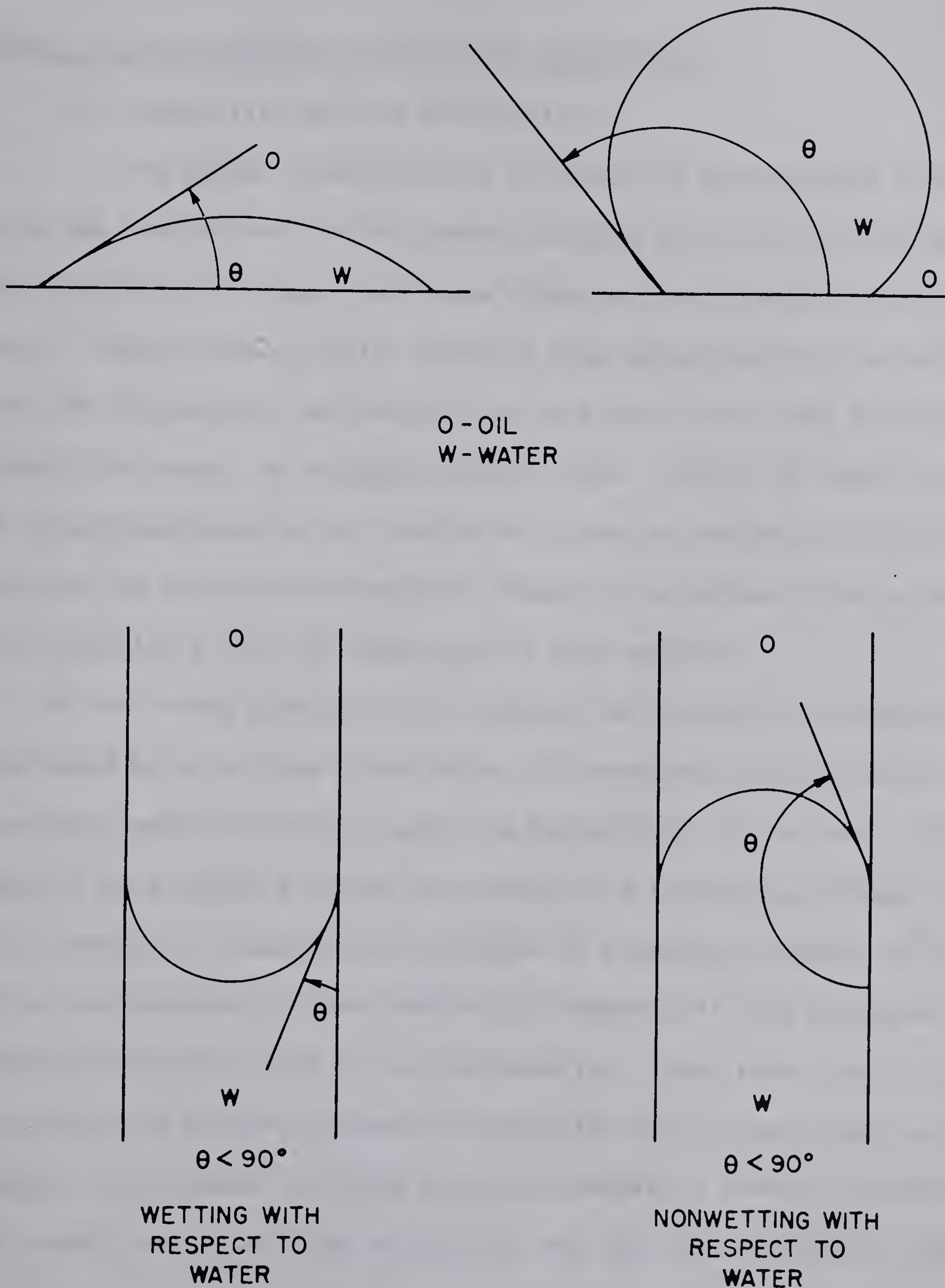
"Preserved core" refers to a core which has been stored by some technique so that its wettability at the wellhead is preserved until the time of testing.

"Extracted core" refers to core which has had it fluid contents removed by the solvent extraction technique, usually in soxhlet apparatus.

"Wettability", qualitatively, denotes the ease with which a fluid can replace other fluids, or spread over a solid surface in presence of other fluids. In a system composed of a solid and two fluids, wettability of the solid is generally expressed in terms of the contact angle formed by the intersection of the interface between the two fluids with the solid surface. The angle is conventionally measured through the liquid phase in solid-liquid-gas systems and through the water in solid-water-oil systems. A fluid which forms a contact angle between 0 deg. and 90 deg. is said to preferentially wet the solid in the particular system and is referred to as the wetting phase. Conversely, a fluid which forms an angle between 90 deg. and 180 deg. is referred to as the non-wetting phase in the particular system.

Application of this definition to two systems of interest is shown in Figure 1. For systems in which the contact angle is 90 deg., the two fluids have equal wetting tendencies for the solid. For a contact angle of 0 deg. or 180 deg., only one fluid is in contact with the surface, that being the wetting phase. Thus "wettability" or "wetting condition" has no meaning except in reference to a complete system consisting of two fluid phases and one solid phase. The contact angle measured represents the wetting condition for these specific fluids and solid and, possibly only for a certain manner of bringing the materials together. In general, the wetting condition of a solid in an oil-water system cannot be inferred from the knowledge of the wetting condition of that solid in air-water and air-oil systems.

FIG. 1 CONTACT ANGLE AND WETTING



LITERATURE REVIEW

Effect of Core Condition on Water-Oil Displacement

(a) Instability of Rock Wettability:

The effect of wettability on water-oil displacement behavior of rocks has been pointed out by several authors (14,15,16,17) who have found that preferentially water wet cores flood more efficiently than oil wet cores. Other authors (18,19) indicate that waterflood oil recovery from cores of intermediate wettability may be greater than that from either strongly water-wet or strongly oil-wet cores. Hence, in order to study the waterflood behavior of in-situ rock, precautions must be taken to maintain the original wettability. Some of the factors which affect the rock wettability will be discusssed in this section.

In the coring operation, the core may be partially or completely penetrated by a drilling fluid which, if containing surface active materials, may drastically change the wettability of the core. Also, improper core handling during the storage and testing may change its wettability because of evaporation of fluids or exposure to oxygen or surface active contaminants. Bobek, Mattax and Denekas (9) have reported the effect of drilling fluid on core wettability. They found that a treated water-base mud reduced the water wettability of the test plug; an oil-emulsion mud rendered the plug neutral; whereas, a commercial oil-base mud caused the wettability behavior of the test plug to invert from water-wet

to oil wet. Furthermore they noted that a change in wettability was due to weathering during long term storage in an oxidizing atmosphere or to "drying out" of the core, in which case some non-volatile components of the residual crude tend to deposit on the pore walls and the core frequently becomes oil-wet. Therefore, they have recommended coring fluids with minimum wettability effects and also two methods of packing the core at the well-head to preserve the core wettability after recovery of the core at the surface. These methods are discussed on page 18 of this work.

The study of the effect of crude oil on wettability by Bobek et. al. (9) resulted in the conclusion that the same core material can be affected differently by different crudes and that the same crude oil can cause different wettability effects in various cores. Therefore, apparently the core and crude oil interact in some manner which causes change in the wetting properties of the core matrix. They indicated that components in the high molecular weight ranges, which are also probably polar in nature, strongly decrease the water wettability of minerals.

Denekas, Mattax and Davis (11) observed that all the crude oils they examined contained a complex variety of surfactants, covering broad ranges of molecular weights and polarities. They also observed that solvent extraction procedures used to remove crude oil from a core almost invariably change the core's wettability.

(b) Core Condition and Water-Oil Flooding:

Studying the effect of core condition on relative permeability, Richardson and Perkins (20) showed that water and oil relative permeabilities of individual samples of rock from the East Texas field were not unique functions of saturation, but that preserved cores from this field had water displacement characteristics that were quite different from

those measured on the same core after cleaning and extraction. In particular, they reported average residual oil saturations of 12 and 30 per cent for fresh and extracted cores respectively, as against 16.6 per cent estimated for the watered out sections of the field. As a result, measurements on fresh cores from this field were recommended for estimating recoverable reserves.

Burkhardt, Ward and McLean (10), in their study, concluded that relative permeability ratio, k_{rw}/k_{ro}, at a particular saturation is greater for the preserved core than for the extracted core. They found that extraction with o.1N NaCl solution, methanol and benzene in sequence altered the core surface and rendered it strongly water-wet. This was also demonstrated by imbibition behavior of preserved and extracted cores. Preserved cores imbibed both oil and water; however, for the most part they imbibed large quantities of oil, whereas extracted samples imbibed no oil but rapidly imbibed large amounts of water.

Ruhl, Schmid and Wissman (6) studied the water-oil displacement behavior of extracted and non-extracted cores. They found that the cores which had not been extracted prior to testing had an earlier water breakthrough and a lower oil recovery than the cores which had been extracted prior to testing. The difference in oil saturation at breakthrough was 13.5% of the pore volume; whereas, at one pore volume throughput it was 14.9%. It should be kept in mind that their non-extracted cores were not protected from the influence of air during storage. Hence, as pointed out by Bobek et al (9), the cores could have undergone a change in wettability during storage.

Colpitts and Hunter (12) studied the effect of core condition at room conditions and at reservoir conditions separately and made the following conclusions:

1. At room conditions, the preserved core flooded more efficiently than the extracted core. They have attributed this to the different wettabilities of the two cores, the preserved core was slightly water wet, whereas the extracted core was neutral.

2. At reservoir conditions, again the preserved core flooded more efficiently than extracted core. This was also believed due to wettability even though they did not measure the wettability at these conditions.

Thus, based on the review of the work done by previous authors, it may be concluded that:

1. The water-oil displacement behavior of preserved cores was invariably different than that of extracted cores.

2. Some authors (6,10) have reported that preserved cores flood less efficiently than extracted cores; whereas,

3. Others (12,20) have reported that extracted cores flood less efficiently than preserved cores.

<u>Effect of Environment Conditions on Water-Oil Displacement</u>

The influence on relative permeability of two of the more obvious effects of high pressure and temperature, i.e. changes in viscosity and interfacial tension, was investigated and reported by Wyckoff and Botset (21). They studied permeability vs. saturation curves for two phase flow in porous media and found little effect on the relative permeability behavior of a carbon dioxide water system when sugar was added to water to increase the viscosity from 0.9 to 3.4 cp, or when amyl alcohol was substituted for water to decrease the surface tension from 72 to 27

dynes/cm. Leverett (22), investigating the effects of liquid viscosity and interfacial tension on the water-oil system, found no significant variation in relative permeability to either oil or water in the system studied when the viscosity ratio was varied from 0.057 to 90.0. Reduction of interfacial tension from about 30 to 5 dynes/cm by substituting amyl alcohol for oil caused a moderate increase in relative permeabilities. Amongst the other possible effects of high temperature and pressure, a change in wettability was observed by Hough, Rzasa and Wood (23) for stainless steel in a methane-water system.

Wilson (5) adopted a more direct approach to the problem and studied the effect of temperature and pressure on the water-oil relative permeability curves using kerosene and simulated reservoir brine with natural sandstone cores. He found that there was no significant effect of either temperature or pressure on the four cores studied, whereas the application of overburden pressure affected the relative permability curves only moderately.

Burkhardt, Ward and McLean (10) have described flooding tests on East Texas (Woodbine) cores at reservoir conditions. They used extracted cores with live oil, and subsurface water for reservoir condition tests. The core was subsequently depressurized and without extraction, was saturated with kerosene up to irreducible water content. This was then followed by a displacement test at room conditions of temperature and pressure, and the permeability curves were evaluated according to Welge (3). On comparing the results the authors did not find any significant effect of temperature, pressure or reservoir fluid.

Kyte, Mattax and Naumann (8) have reported flooding and imbibition tests conducted on limestone cores at reservoir conditions.

Waterflood tests were first performed on preserved core, at room temperature and pressure, using refined oil. These tests were repeated on the same sample, using crude oil, at reservoir conditions of temperature and pressure. Tests on five such core samples at reservoir conditions showed an average recovery of 55% of original oil in place after injection of one pore volume of water; whereas, for the same samples at room conditions, the recovery was 39%.

The authors also performed imbibition tests on preserved core at room and reservoir conditions. At room conditions they used the apparatus and procedures described by Bobek et al (9). The equipment used for reservoir condition imbibition test has been described in their paper. The rock samples from two out of three reservoirs under study, which had intermediate wettability characteristics at surface conditions, became strongly water-wet at reservoir conditions. Thus, according to these authors, an absorption of high molecular weight and polar components of crude oils on the rock surface occurs when reducing the original temperature and pressure of the rock sample. Consequently, the previously water-wet core is changed in its wettability to intermediate or occasionally oil-wet conditions. In their subsequent flooding tests at reservoir conditions (increased temperature) a desorption of polar components appeared to occur with the flooding tests showing typical results of the water-wet conditions.

Ruhl, Schmid and Wissman (6) have presented the results of waterflood tests on larger extracted core samples. They observed a 5% higher oil recovery at three pore volumes of water injected, when using refined oil at ordinary temperature than, when using live oil at reservoir temperature and pressure. At water breakthrough the difference was about 2 to 3%.

They also found that there was no difference between the waterflood efficiency of an extracted core using live oil at elevated conditions of temperature and pressure, and using tank oil at ordinary conditions of temperature and pressure. Furthermore, capillary pressure curves showed that the fresh core, and the core temporarily saturated with reservoir liquids and kept under reservoir conditions for three days, behaved similarly; whereas, the extracted core behaved differently. Therefore, it was concluded that temporary saturation with reservoir oil leads to a wettability which is similar to the wettability in the reservoir. The proof of this argument is restricted by the fact that capillary pressure measurement on the extracted cores, temporarily saturated with reservoir fluid, was done after reduction of temperature and pressure to room conditions. Hence, the temperature reduction, as pointed out by Kyte et al (8), could have caused adsorption of polar components, and consequently the change in wettability conditions. However, the waterflood results do not indicate that the change in wettability would occur only after the reservoir temperature of the reservoir-fluid-saturated core had decreased to room temperature level. Thus, they concluded that temperature and pressure exert very little influence upon the waterflood performance. However, the use of refined oil with extracted cores is inappropriate because it causes different wettability conditions. The use of tank-oil with gasoline (to give the same viscosity ratio) presents the problems of paraffin deposits. Thus, flooding tests using reservoir fluid, at reservoir conditions of temperature and pressure on extracted cores, according to the authors, gives results which are most representative for the development of oil recovery in the reservoir.

Colpitts and Hunter (12), in order to isolate the effect of environment conditions from core condition effect, used paired samples. One plug from each pair was flooded at reservoir conditions, the other plug at room conditions. Live oil was used for reservoir condition test; whereas, refined oil was used for room condition tests. In all the 13 pairs they tested they found that with preserved cores the reservoir condition recovery was greater than room condition recovery. With extracted cores, recovery was independent of test environment, and less efficient than preserved cores.

Hence, the review of the literature regarding the effect of test environment of the water-oil displacement tests reveals that:

(1) Some authors (5,6,10) believe that temperature and pressure have no effect on the waterflood behavior of core samples, whereas,

(2) Others (8,12) observed that the preserved cores flood more efficiently at reservoir conditions of temperature and pressure than at the room temperature and the atmospheric pressure.

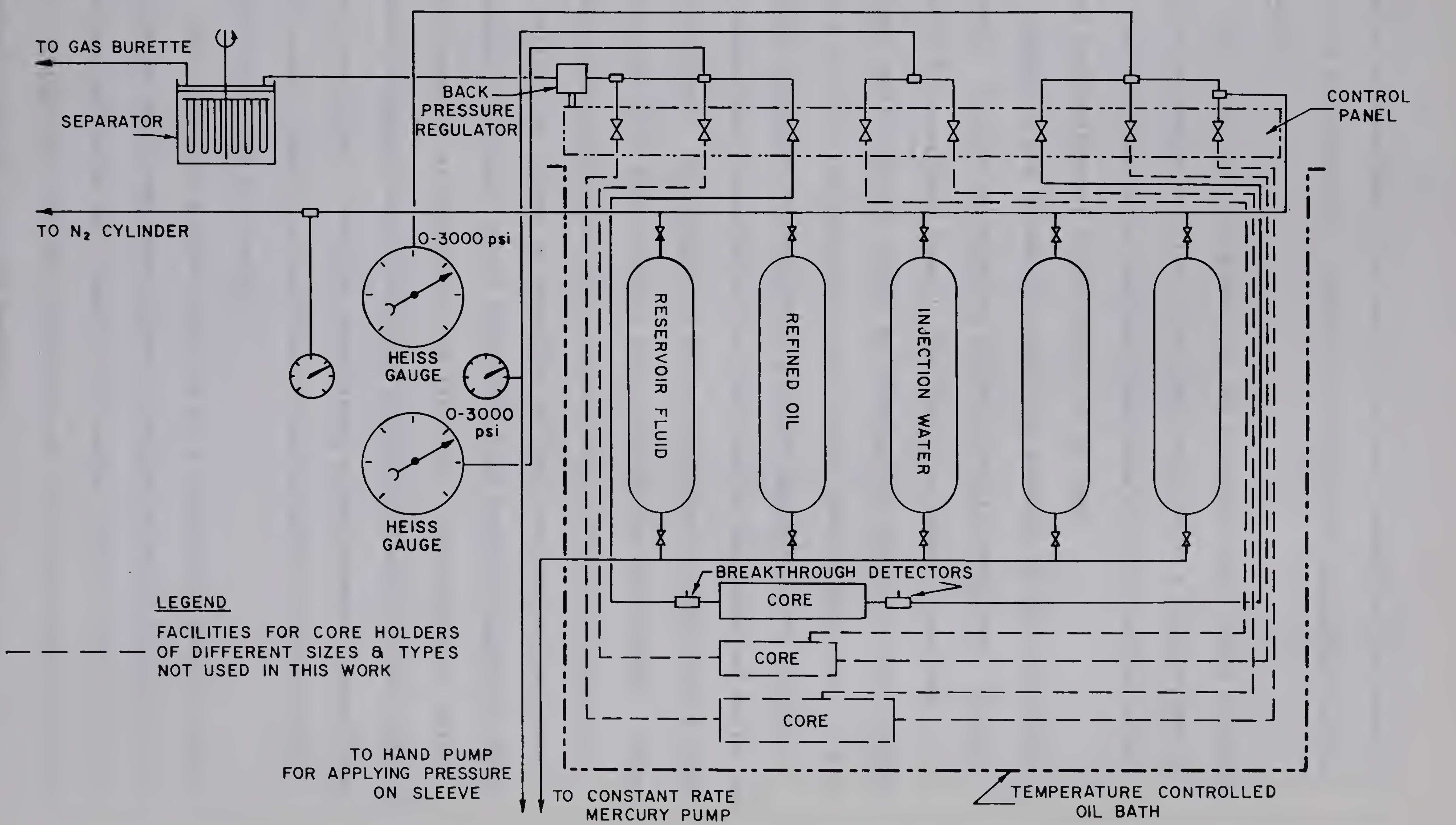
EQUIPMENT

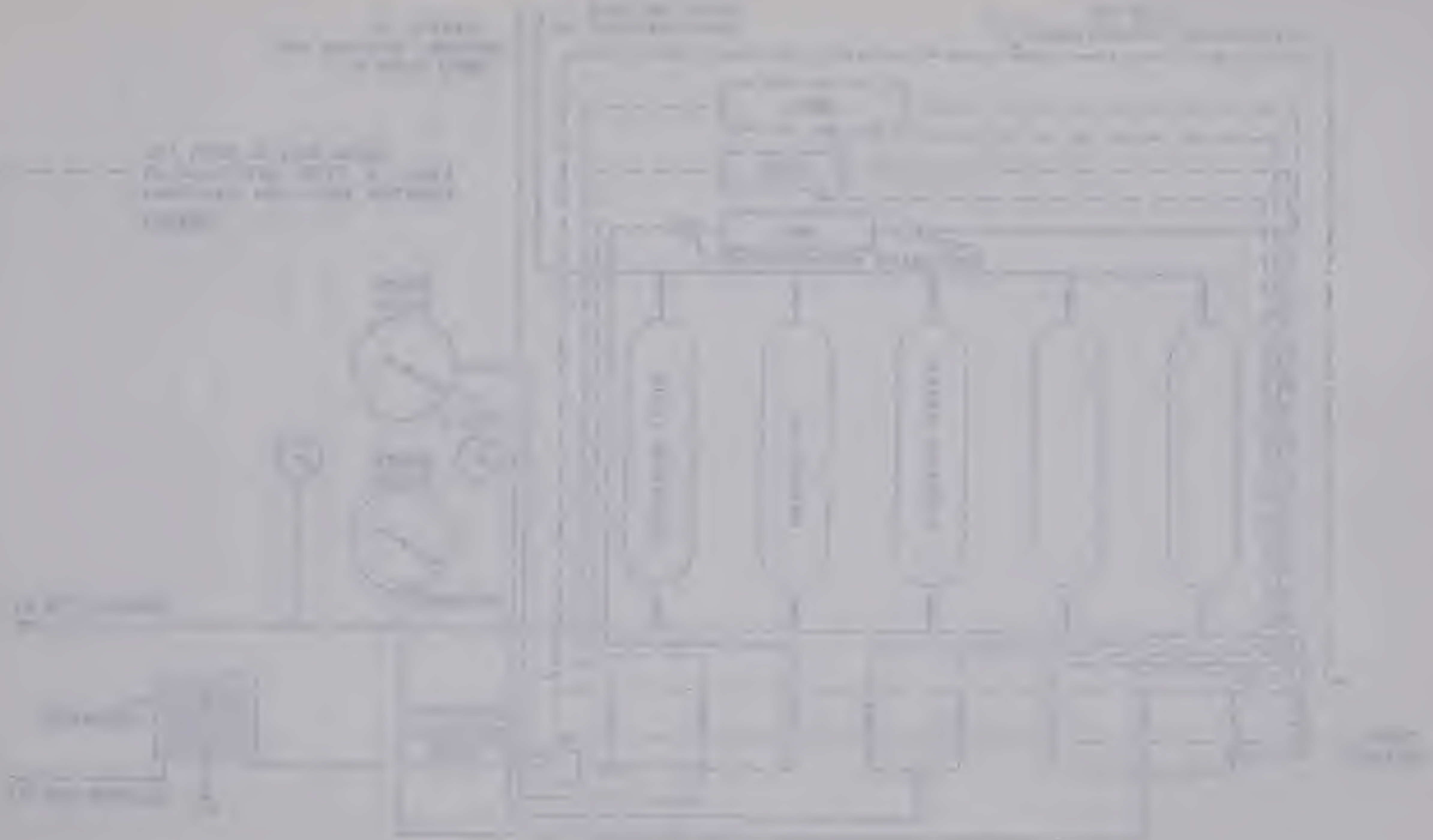
The apparatus employed for this work was designed to permit the testing of waterflood behavior of rock samples at fluid pressures up to 3,000 lbs/square inch and of temperatures up to 250°F. Figure 2 shows the schematic flow diagram of the equipment. Schematically, a constant rate mercury injection pump was connected to the five fluid cells in parallel. Three of these cells contained the reservoir oil, the refined oil and the injection water respectively. The cells were connected to the core holder, which, in turn, was connected to the collection system.

In order to maintain a desired constant temperature for the waterflood test, most of the equipment, i.e. the fluid cells, the core holder and the flow lines were installed in a constant temperature oil bath. The rectangular bath (3' x 2' x 2') was made of copper and, to prevent excessive heat loss, the sides and bottom of the bath were covered with wooden panels. At the bottom, it was supported by an hydraulic pump, which controlled the height of the bath on a four legged iron frame with the help of wheels attached to the corners of the bath. Iron cross-bars at the top of the iron frame supported the fluid cells and the core holder.

The bath was equipped with four heating coils of 1,000 watts each, which were inserted from the bottom of the bath. The bath was filled with Marcol 70, a local Imperial refinery product, which has a high flash point. The oil was stirred by means of a stirrer (Jumbo Stirrer, Fisher Scientific), connected to one of the cross-bars at the top of the iron frame. The temperature of the bath was controlled by means of a temperature sensitive element, which was also connected to one of the cross-bars at the top of the iron frame. This temperature sensitive element was

FIG. 2 SCHEMATIC DIAGRAM OF RESERVOIR CONDITION FLOODING EQUIPMENT





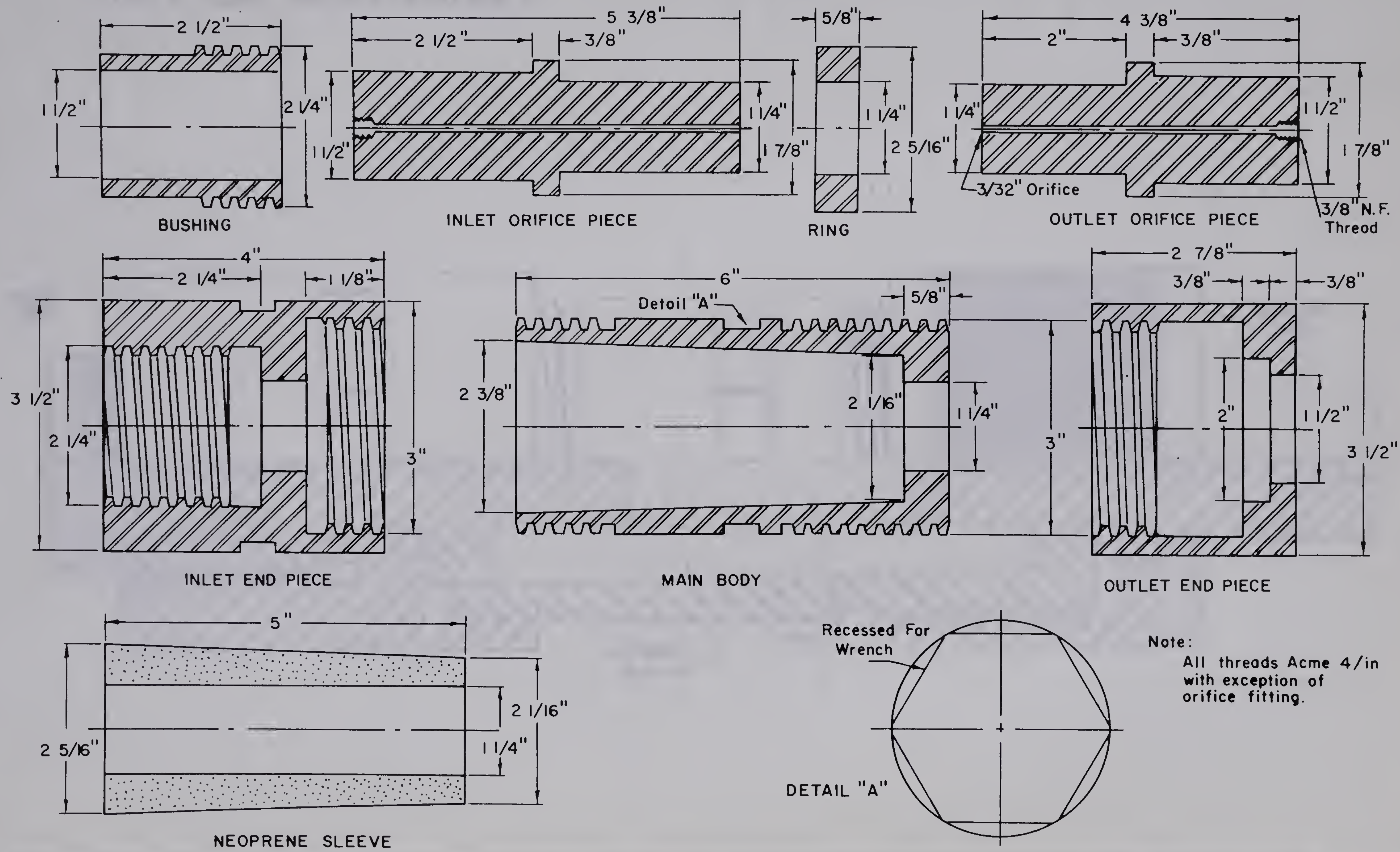
connected to an electronic relay which, in turn, controlled the heater's switches. It was, therefore, possible to control the temperature of the bath to $\pm 0.1^{\circ}C$.

The fluid cells were made of 316 stainless steel which is fairly resistant to corrosion by brine. Each cell could hold a fluid volume of 1 liter. All the flow lines used were also made of 316 stainless steel, and had an inside diameter of one eighth of an inch.

Figures 3 and 4 show the parts and assembly of the core holder respectively. In order to make the holder corrosion resistant, it was also made of 316 stainless steel. The sleeve was made of neoprene. Pressure was applied on the sleeve by screwing the inlet end piece inwards (see Figure 3). For the particular core holder used in this work, it was not possible to measure the amount of pressure applied on the sleeves. Electric probes were installed in the flow line at the inlet and outlet end of the core holder. The purpose of these probes was to detect the entrance and exit of the first drop of water into and from the core holder. These probes were connected to electronic relays which actuated the electric bells as well as the lights on detection of the first drop of the water. A back pressure regulator (Grove Mitty-Mite Back Pressure Regulator, Model 91 XW) was connected at the end of the flow line. The purpose of this back pressure regulator was to maintain a desired pressure at the outlet end of the core holder. Thus, by maintaining a back pressure higher than the bubble point pressure of the crude, it was possible to obtain single phase flow through the core sample.

The collection system comprised of a cylindrical plastic separator with twelve centrifuge tubes inserted through holes in a plastic plate. This plate was supported by a shaft at the center, which could be rotated in order to change the tube for collecting oil. The gas separated in this separator was collected in a gas burette.

FIG. 3 PARTS FOR CORE HOLDER



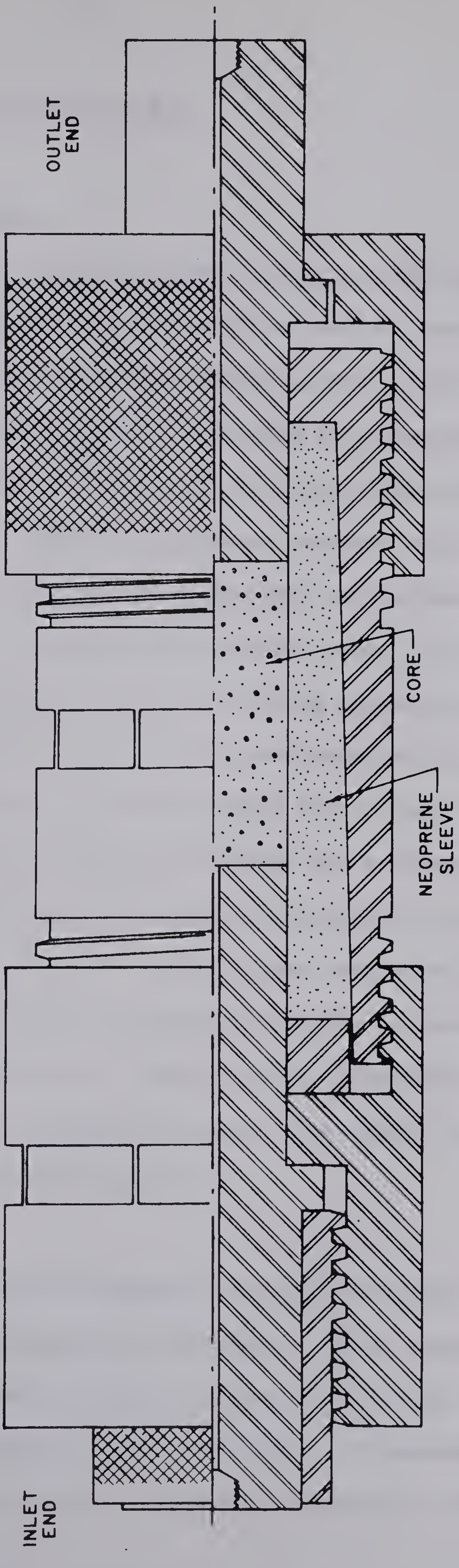


FIG. 4 CORE HOLDER ASSEMBLY

PROCEDURE

Core Handling and Preparation

In any attempt to study the effect of core condition, it is desirable to use the wettability of the in-situ reservoir rock as a reference condition. If cored with a carefully selected drilling fluid, the preserved core should come closest to meeting this requirement.

Bobek et al (9) and Denekas et al (11) have given some guide to the controlled mud systems required to maintain original wettability during coring. Bobek et al (9) have also proposed two methods for the preservation of original core wettability during storage. The object of such a storage is to prevent the core from being exposed to air (i.e. to avoid oxidation and drying). In one, the core material is immersed in deoxygenated formation brine, contained in glass lined steel tubes which can be sealed against content leakage and against the entrance of oxygen. In the other procedure, the individual samples are placed in polythene bags and taped tightly excluding the air. Each is then wrapped with heavy duty aluminum foil, taped again, placed in boxes and sealed by covering with low melting parawax. Once the box is opened in the laboratory, the cores should always be kept under deoxygenated brine. The latter technique was used in preserving the cores for this work.

Reservoir Condition Test

The plug, after initial weighing, was saturated with brine under a vacuum, weighed and mounted in the core holder. Teflon tape was wrapped around the plug to avoid direct contact of rubber sleeve with the plug. It was then flushed with synthetic formation brine (see appendix A) in order to remove all the mud filtrate. This was followed by a viscous

refined oil (Imperial Oil's Zerice 36) flush to speed the removal of water in establishing irreducible water saturation. The amount of brine produced was noted to give a value of the initial water saturation.

The core holder was placed in a temperature controlled bath and flushed with refined oil of approximately the same viscosity as the reservoir oil. CLCGO - after treat - J unit, a local Imperial refinery product, was used in this case. This step was necessary to reduce the amount of reservoir oil required. The use of reservoir oil necessitates the downstream pressure to be greater than the bubble point of reservoir oil to avoid three phase flow in the core. Hence, the back pressure regulator was always maintained at a pressure of 2500 psig. The bath was heated to the reservoir temperature (190°F) and the excess pressure of the fluid cells was bled off from time to time. After the desired temperature was reached, the reservoir oil was injected through the core until a constant pressure drop across the core was obtained (usually the amount required was about 10 pore volumes). After attaining steady state flow exactly 10 cc. of reservoir oil was flowed through the core, and collected for use in obtaining the oil formation volume factor.

The waterflood was then started by closing the reservoir-oil cell valve and opening the water cell valve. Injection water was made to simulate the water that would be used for waterflooding the field from which the core was taken. Deaerated tap water was found to be suitable for this purpose. From the time water entered the core holder (indicated by the water detector, see Figure 2), the pressure, injected water volume and time were recorded. Water breakthrough was determined by the water breakthrough detector (see page 15). Successive fractions of fluids were produced in different tubes in the collection system.

The test was normally stopped after injecting ten to twenty pore volumes of water. The temperature and pressure of the system were

reduced to room temperature and pressure. The amount of fluids produced in the process of depressurization was recorded and later used in the determination of the final water saturation of the plug at the end of the waterflood. The plug was taken out of the core holder and weighed. The water saturation of the plug was determined at the end of the run using the Dean and Stark method (24). When the volume of water in the trap became constant under continued extraction, the volume of water collected was read and the thimble containing the core was transferred to the soxhlet apparatus for final extraction.

In the case where the tubes contained an oil-water mixture, the individual volumes were measured gravimetrically. The tube was first weighed with mixture in it, then oil was absorbed in a porous plastic. Vyon, a product of Porous Plastics Limited, Essex, England, treated with General Electric dry film SC87 to render it oil-wet, was used. The tube containing only water was weighed. The difference in weight when divided by the specific gravity of oil gave the volume of oil in the tube. The volume of water was read directly.

Room Condition Test

In principle, the procedure for the room condition test was the same as for the reservoir condition test.

The dry plug was weighed, saturated with brine under a vacuum and weighed again. The difference in these two weights along with the density of the brine was used to calculate the pore volume of the plug. Teflon tape was then wrapped around the plug, mounted in the core holder and flooded with a few pore volumes of brine to measure its permeability. This was followed by a viscous oil flush with Zerice 36. The volume of water produced was used to calculate the initial water saturation.

The viscous oil flush was followed by a refined oil flush. The refined oil used had a viscosity which gave the same viscosity ratio as during the reservoir condition test. This consisted of a mixture of Varsol and CLCGO. After approximately 15 pore volumes of refined oil had been passed through the sample the waterflood was initiated. During the life of the flood, pressure, time and volume of water injected were recorded. The test was terminated when the producing water oil ratio had reached or exceeded 100. The final water and oil condition was again determined by means of the Dean and Stark method.

MODEL SCALING

Rapoport and Leas (2) have indicated that the behavior of a linear flood is determined not only by the nature of the porous medium (i.e. specific values of porosity, permeability, relative permeability function and capillary pressure function, etc.), and the fluid system (defined by its viscosity ratio, interfacial tension, and contact angle), but also by the length of the flooded system and the rate of injection. Hence, for any meaningful comparison of displacement test results, taken on the same or different cores, or projection of results from laboratory observations to an expected behavior on field scales, special care must be exercised in selecting the flow rate and the physical parameters of the system to be investigated.

The influences of this nature are known as "scale effects" and an experiment designed to be independent of such "scale effects" would be "dimensionally scaled" experiment. Such an experiment may be designed by proper selection of flow rates, fluid properties, and the physical parameters of the system, under investigation as dictated by the use of the "dimensional analysis" or its modern successor "inspectional analysis".

Geertsma et al (25) first utilized the concept of dimensionless groups to scale laboratory experiments involving immiscible flow discplacement. Engelberts and Kinkenberg (26) extended this work. Rapoport and Leas (2) used the concept of inspectional analysis to derive scale-up laws. Geertsma et al (25) and Perkins et al (27) have extended scale-up laws given by Rapoport. Croes et al (28) and others (29, 30, 31, 32, 33) have experimentally verified them.

This work has made use of the criteria given by Rapoport and Leas (2), because of their practical adaptability. They found that:

"Accordingly, the product, $L V \mu_w$, may be qualified as a "scaling coefficient", and it can be stated that for a given porous medium and a given oil-water viscosity ratio all floods corresponding to the same scaling coefficient must behave similarly and yield equal recoveries for equal cumulative injections. This statement implies that (a) the recoveries and cumulative injections are expressed in terms of pore volumes; (b) all the systems under consideration possess the same initial saturation distribution; and (c) changes in the viscosity of the fluids do not alter the shape of the capillary pressure curve".

In addition, when they plotted oil recovery at breakthrough in per cent pore volume versus the scaling coefficient ($L V \mu_w$), they observed that as the scaling coefficient increases the oil recovery at breakthrough increases; however, above a certain "critical" value of the scaling coefficient, the oil recovery at breakthrough becomes constant and independent of rate, length and water viscosity. Such a situation, according to Rapoport and Leas, is indicative of stabilized flooding behavior.

From a practical viewpoint, it is necessary to consider the recovery data not only for breakthrough but for the entire flood. Rapaport and Leas have shown that: "... that stabilization at breakthrough ensures stabilization of the entire flooding process".

To determine the value of "critical scaling coefficient" for this work, a representative core was taken, cleaned with toulene in soxhlet apparatus for 48 hours, and dried in the oven at 200°F for 48 hours. Water-oil displacement tests were then conducted on this extracted core at 4 different injection rates (10, 20, 40 and 80 ccs/hour) using deareated

tap water as the displacing fluid and varsol as the displaced fluid. The core was cleaned and dried at the end of every test.

Figure 5 shows a plot of oil recovery at water breakthrough versus the scaling coefficient ($LV\mu_w$) for this core. It may be observed that the oil recovery at breakthrough increases linearly with an increase in the scaling coefficient, up to a critical value of 4.2 cm^2 x cp/min., after which it stays constant. Thus any water-oil displacement test conducted on this core and water-varsol system of fluids, at a rate corresponding to scaling coefficient of 4.2 cm^2 x cp/min., or higher, should be "stabilized".

Strictly speaking, this value of critical scaling coefficient would be applicable only to this particular core and water-varsol system, but, for practical reasons, it was assumed to be valid for all the runs reported in this work. Although, the validity of this assumption may be questioned, it was felt that since the value of scaling coefficients ($LV\mu_w$) for all the tests fell into a fairly narrow range (4.38 to 5.66 cm^2 x cp/min.), the results obtained were comparable one to another.

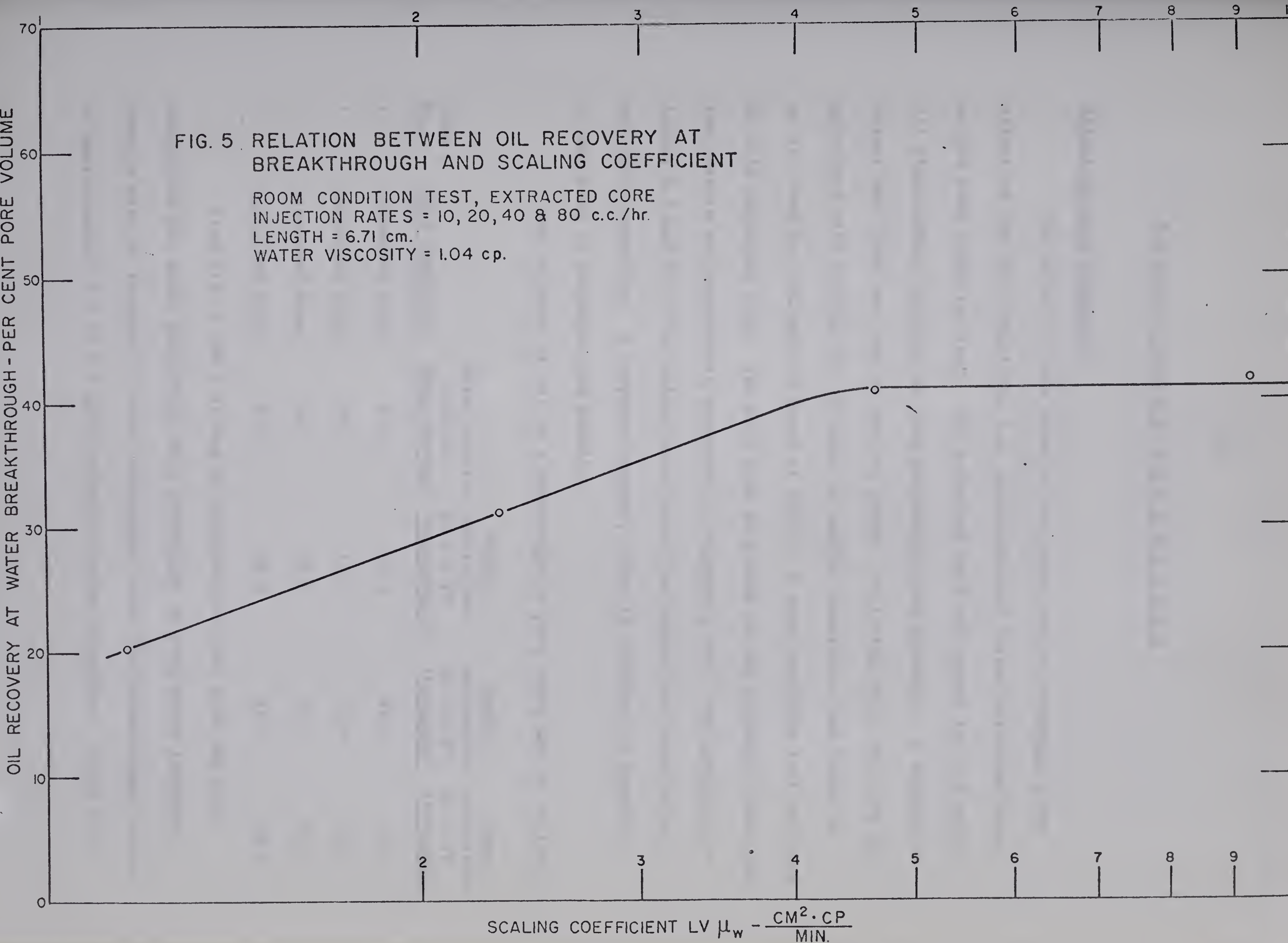


FIG. 5 RELATION BETWEEN OIL RECOVERY AT BREAKTHROUGH AND SCALING COEFFICIENT

ROOM CONDITION TEST, EXTRACTED CORE
INJECTION RATES = 10, 20, 40 & 80 c.c./hr.
LENGTH = 6.71 cm.
WATER VISCOSITY = 1.04 cp.

RESULTS AND DISCUSSION

Effect of Core Condition

The object of this phase of the study was to investigate the effect of the core condition, i.e. preserved core versus extracted core, on the room condition test. The preserved core was tested for its water-oil displacement behavior at room temperature and pressure. A mixture of Varsol and CLCGO was used as the oil phase. Following this, the core was extracted with Toulene for 48 hours in soxhlet apparatus, and dried in an air oven for the next 48 hours at 250^{o}F. A room condition test was made on this extracted core. Two such runs were made on two different cores and the results are graphically presented in Figures 6 and 7 and tabulated in tables D-1 and D-2. The tables also report the visual core description and core properties. A computer program, which is included in Appendix C, was used to calculate the results.

The recovery of oil as a percentage of pore space was as follows:

Core No.	Core Condition	Water Saturation at Breakthrough	Water Saturation at 1.5 PV Throughouput	Water Saturation at 3.0 PV Throughput	Water Saturation at 5 PV Throughput
1	Preserved Core	43.5	63.3	69.0	72.1
1	Extracted Core	60.5	71.2	72.0	72.7
2	Preserved Core	48.7	58.4	62.5	54.5
2	Extracted Core	61.0	68.0	67.7	58.8

From Fig. 6 and 7 it may be observed that for both the core conditions the water saturation as a percentage of pore space increases sharply with an increase in water throughput until the breakthrough occurs at approximately 0.3 to 0.5 pore volumes of water injection. After the

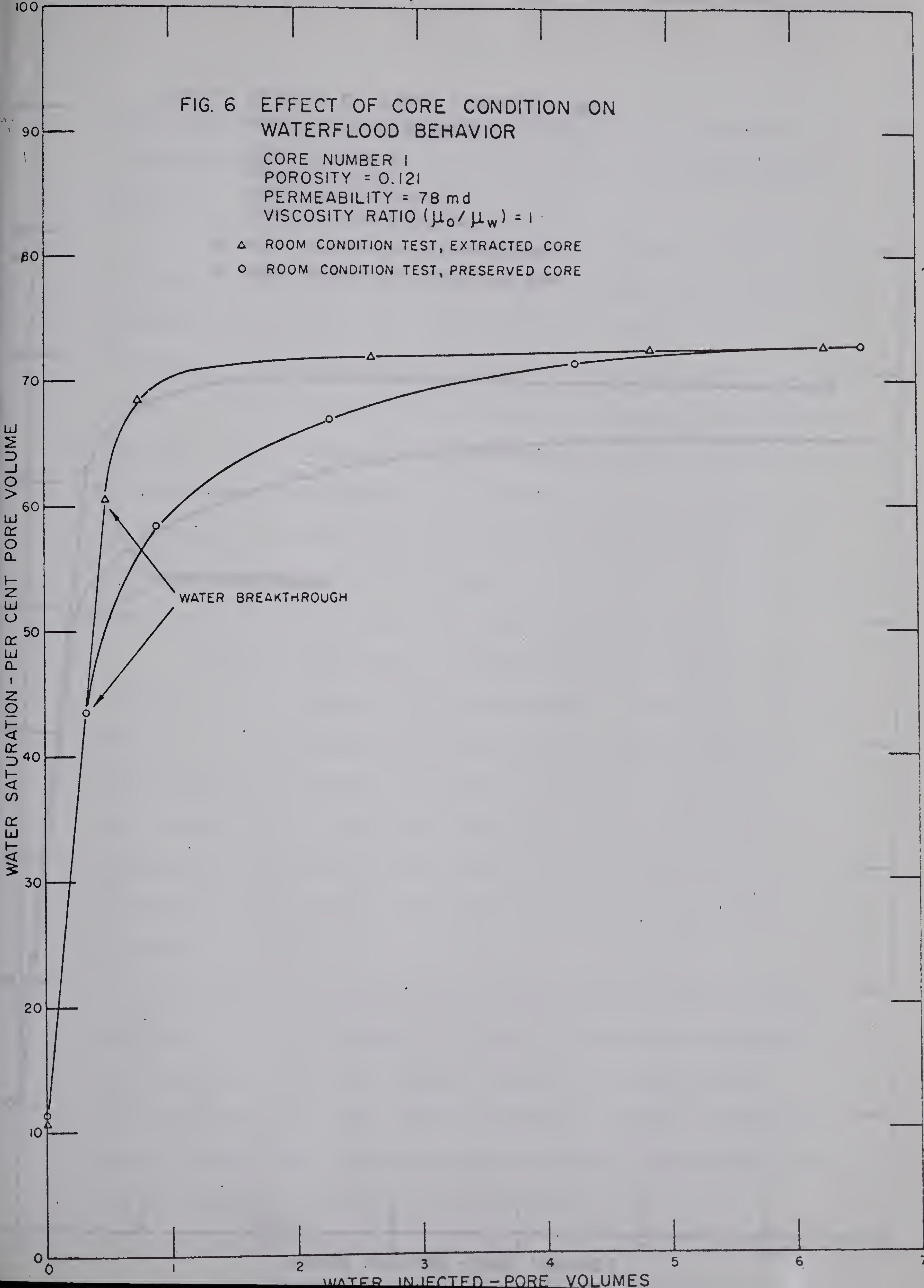
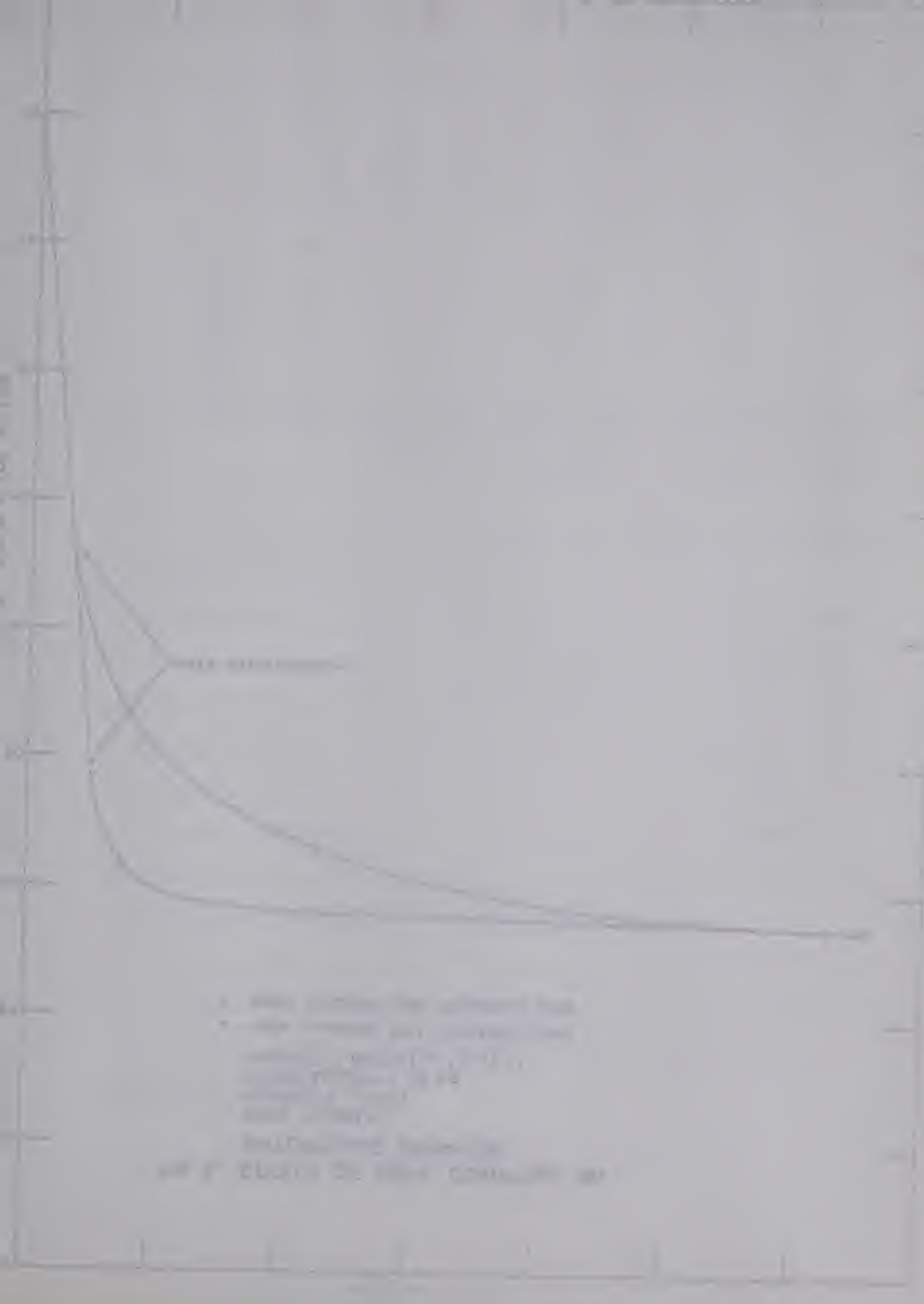


FIG. 6 EFFECT OF CORE CONDITION ON WATERFLOOD BEHAVIOR
CORE NUMBER I
POROSITY = 0.121
PERMEABILITY = 78 md
VISCOSITY RATIO (μ_o / μ_w) = 1
△ ROOM CONDITION TEST, EXTRACTED CORE
○ ROOM CONDITION TEST, PRESERVED CORE
WATER BREAKTHROUGH
WATER SATURATION - PER CENT PORE VOLUME
WATER INJECTED - PORE VOLUMES
0
10
20
30
40
50
60
70
80
90
100
1
2
3
4
5
6
7



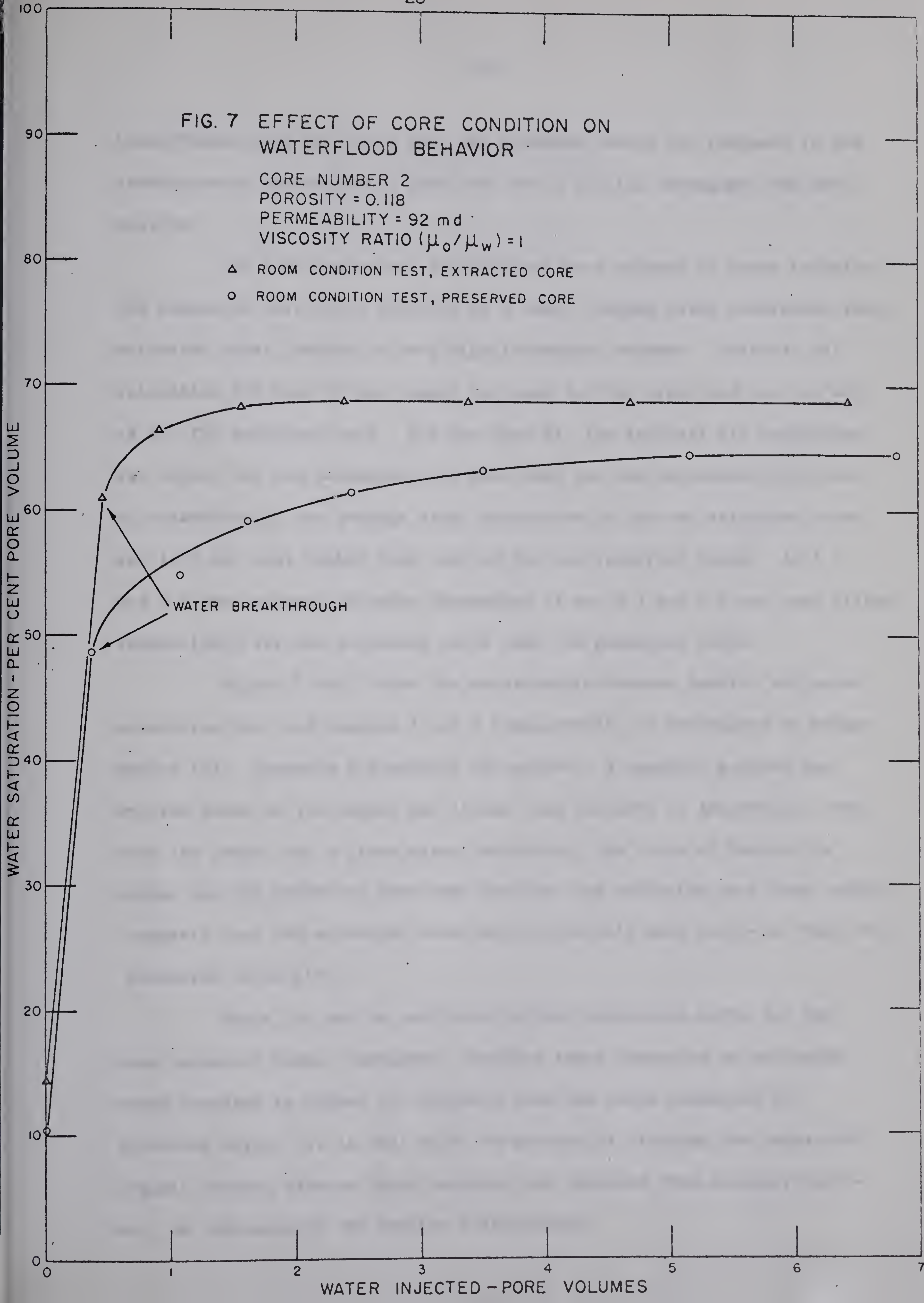


FIG. 7 EFFECT OF CORE CONDITION ON WATERFLOOD BEHAVIOR
CORE NUMBER 2
POROSITY = 0.118
PERMEABILITY = 92 md
VISCOSITY RATIO (μ_o/μ_w) = 1
△ ROOM CONDITION TEST, EXTRACTED CORE
○ ROOM CONDITION TEST, PRESERVED CORE
WATER BREAKTHROUGH
WATER SATURATION - PER CENT PORE VOLUME
WATER INJECTED - PORE VOLUMES
0
10
20
30
40
50
60
70
80
90
100
1
2
3
4
5
6
7

breakthrough, oil and water both are produced, hence the increase in the average water saturation of each core for a similar throughput was much smaller.

For both the cores, for the same pore volumes of water injected, the preserved core tests resulted in a lower average water saturation than extracted cores, except at very high throughput volumes. Residual oil saturation for Core #1 was almost the same for the preserved core as well as for the extracted core. But for Core #2, the residual oil saturation was higher for the preserved core case than for the extracted core case. At breakthrough, the average water saturation of the two extracted cores was 14.9 per cent higher than that of the two preserved cores. At 1.5 and 3.0 pore volumes of water throughput it was 8.7 and 4.1 per cent higher respectively for the extracted cores than the preserved cores.

Figure 8 and 9 show the relationship between krw/kro and water saturation for core numbers 1 and 2 respectively, as determined by Welges Method (3). Appendix B describes the method. A computer program was written based on the method and it has been included in Appendix C. For both the cores, for a given water saturation, the value of krw/kro is higher for the preserved core case than for the extracted core case, which suggests that the extracted cores were relatively more water-wet than the preserved cores (10).

Hence, it may be said that in this particular work, for the same volume of water throughput, flooding tests conducted on extracted cores resulted in higher oil recovery than the tests conducted on preserved cores. It is felt that the process of cleaning the cores with organic solvent altered their surfaces and rendered them strongly water-wet, as indicated by the krw/kro relationship.

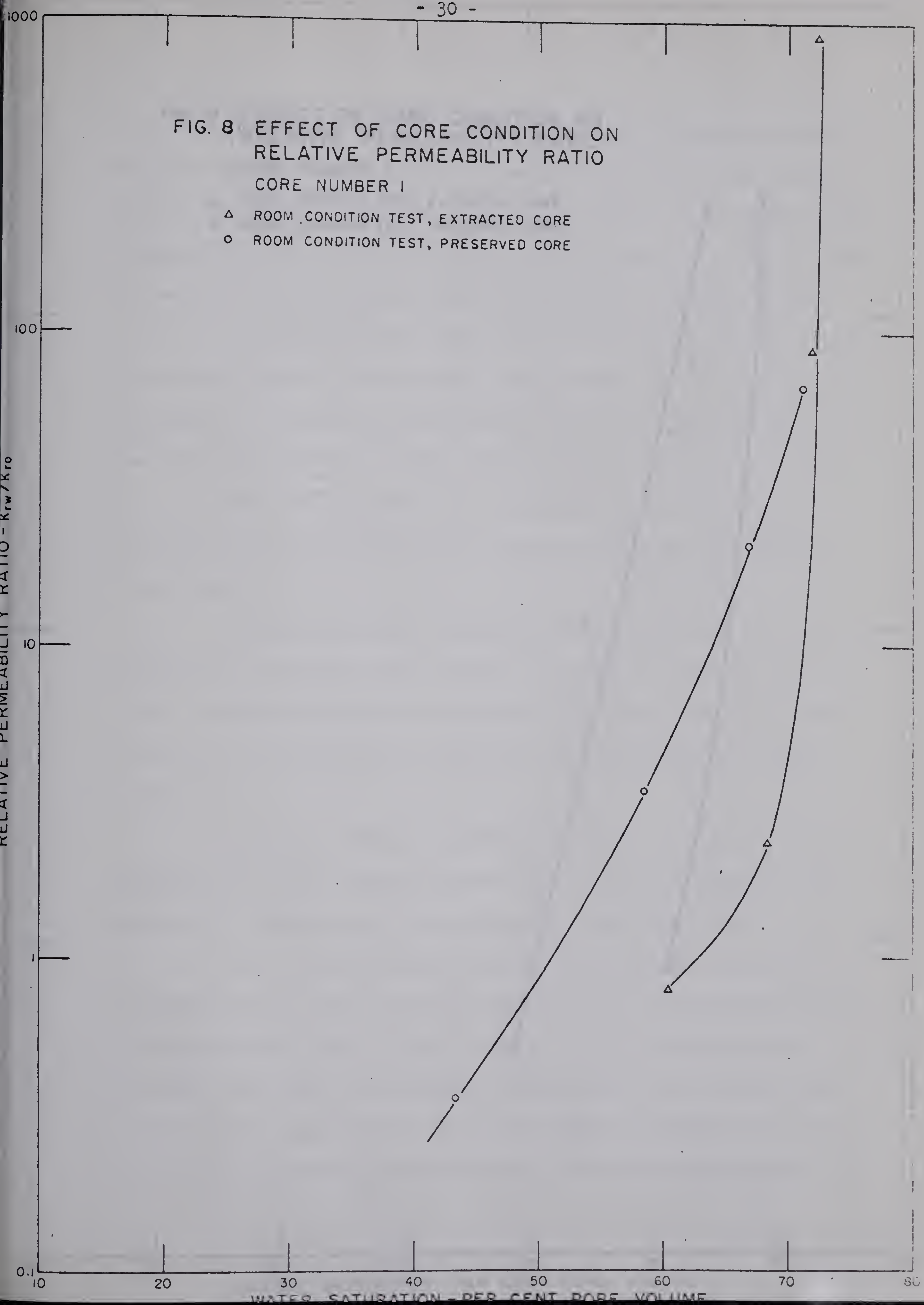


FIG. 8 EFFECT OF CORE CONDITION ON RELATIVE PERMEABILITY RATIO
CORE NUMBER I
△ ROOM CONDITION TEST, EXTRACTED CORE
○ ROOM CONDITION TEST, PRESERVED CORE
RELATIVE PERMEABILITY RATIO - Krw/Kro
1000
100
10
1
0.1
10
20
30
40
50
60
70
80
WATER SATURATION - PER CENT PORE VOLUME

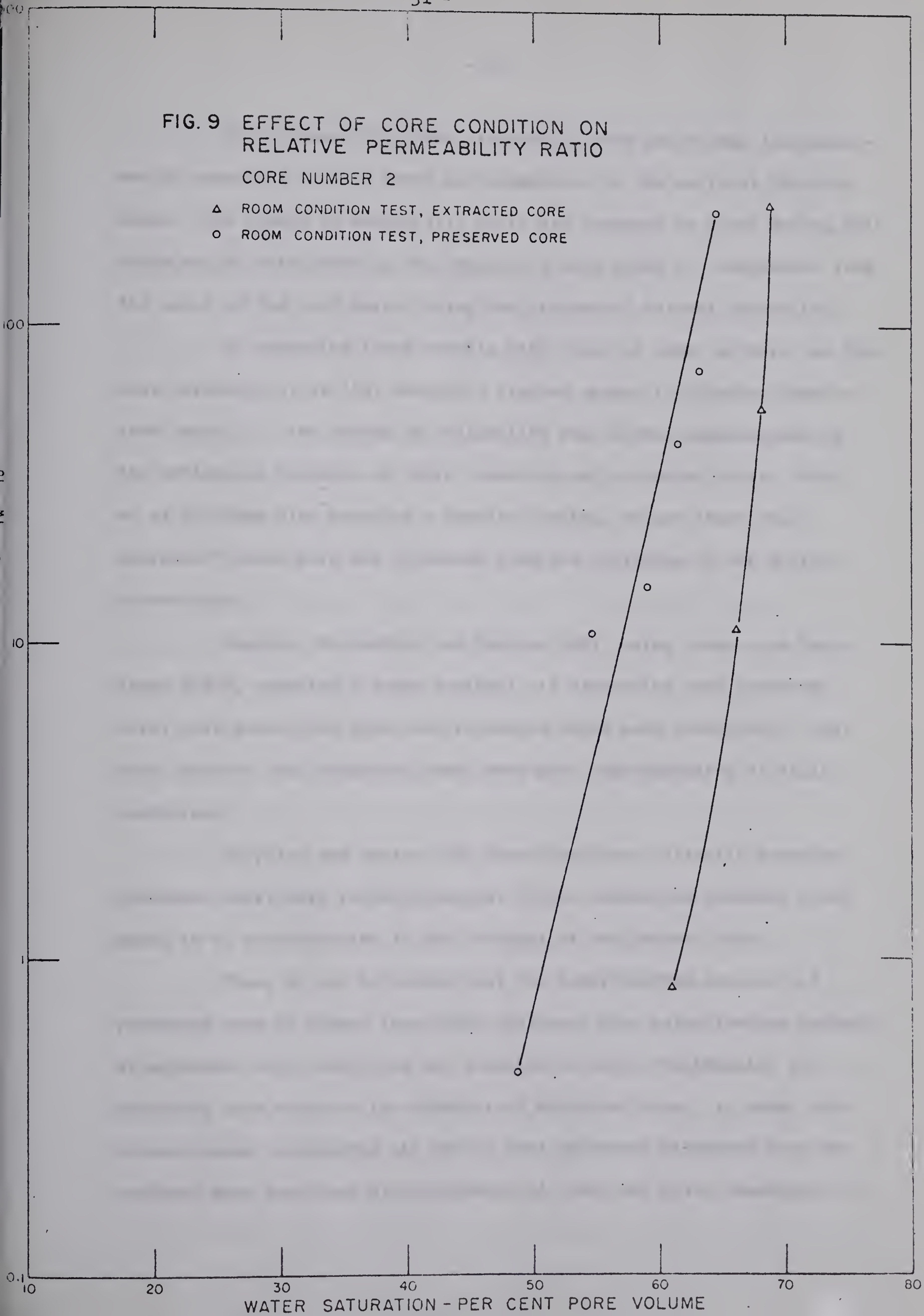


FIG. 9 EFFECT OF CORE CONDITION ON RELATIVE PERMEABILITY RATIO

It is known (9,11) that reservoir rocks can become less water-wet by absorbing certain crude oil components on the walls of the rock pores. The change in wettability which was observed to occur during this study may be attributed to the removal of such crude oil components from the walls of the rock pores during the process of solvent extraction.

In comparing these results with those of other authors, we find that Burkhardt et al (10) noticed a similar change in flooding behavior (see Page 7). The change in wettability was further demonstrated by the imbibition behavior of their preserved and extracted cores. Ruhl et al (6) have also reported a similar finding, except their "not extracted" cores were not protected from the influence of air during preservation.

However, Richardson and Perkins (20), using cores from East-Texas Field, reported a lower residual oil saturation when preserved cores were waterflood than when extracted cores were waterflood. They also observed that preserved cores were more representative of field conditions.

Colpitts and Hunter (12) found that their slightly water-wet preserved cores were rendered neutral by the extraction process, which again is in contradiction to the findings of the present work.

Thus, it may be stated that the waterflooding behavior of preserved core is almost invariably different than waterflooding behavior of extracted core, and it is not possible to infer the behavior of preserved core based on the behavior of extracted core. It seems that in some cases, a slightly oil wet or less water-wet preserved core was rendered more water-wet by the removal of heavy and polar components of

the crude oil during the process of extraction, whereas an originally strongly water-wet preserved core was rendered less water wet due to the contact with Toulene.

Combined Effect of Test Environment and Core Condition

Earlier workers (6,8,12) have indicated that preserved core waterfloods at reservoir conditions using live oil most closely represent the displacement that is occurring in the reservoir. The costs of conducting such tests are many times more than that for extracted waterfloods at room condition. Hence, the object of this phase of the work was to compare the waterflood behavior of the preserved core at reservoir condition using reservoir oil, to the waterflood behavior of the extracted core at room conditions using refined oil. It would have been desirable to use live oil for reservoir condition tests, but for practical reasons, a recombined sample was used instead.

The waterflood test was run on a preserved core at reservoir conditions, which was subsequently extracted with Toulene for 48 hours in soxhlet apparatus. The core was dried in an oven for 48 hours or until it attained a constant weight at 250°F. A room condition test was run on this extracted core, using a mixture of Varsol and CLGGO to provide the proper viscosity ratio and deareated tap water as the displacing phase. Four such runs were made on four different cores and the results are presented graphically in Figs. 10 to 14. Tables D-3 to D-6 report the visual core description and core properties. A computer program included in Appendix C was used to calculate the results. Figs. 10 to 14 represent typical water-oil displacement curves showing average water saturation of core samples versus the amount of water throughput expressed as percentage of pore volume. Figures 14 to 17 show the plot of krw/kro versus average

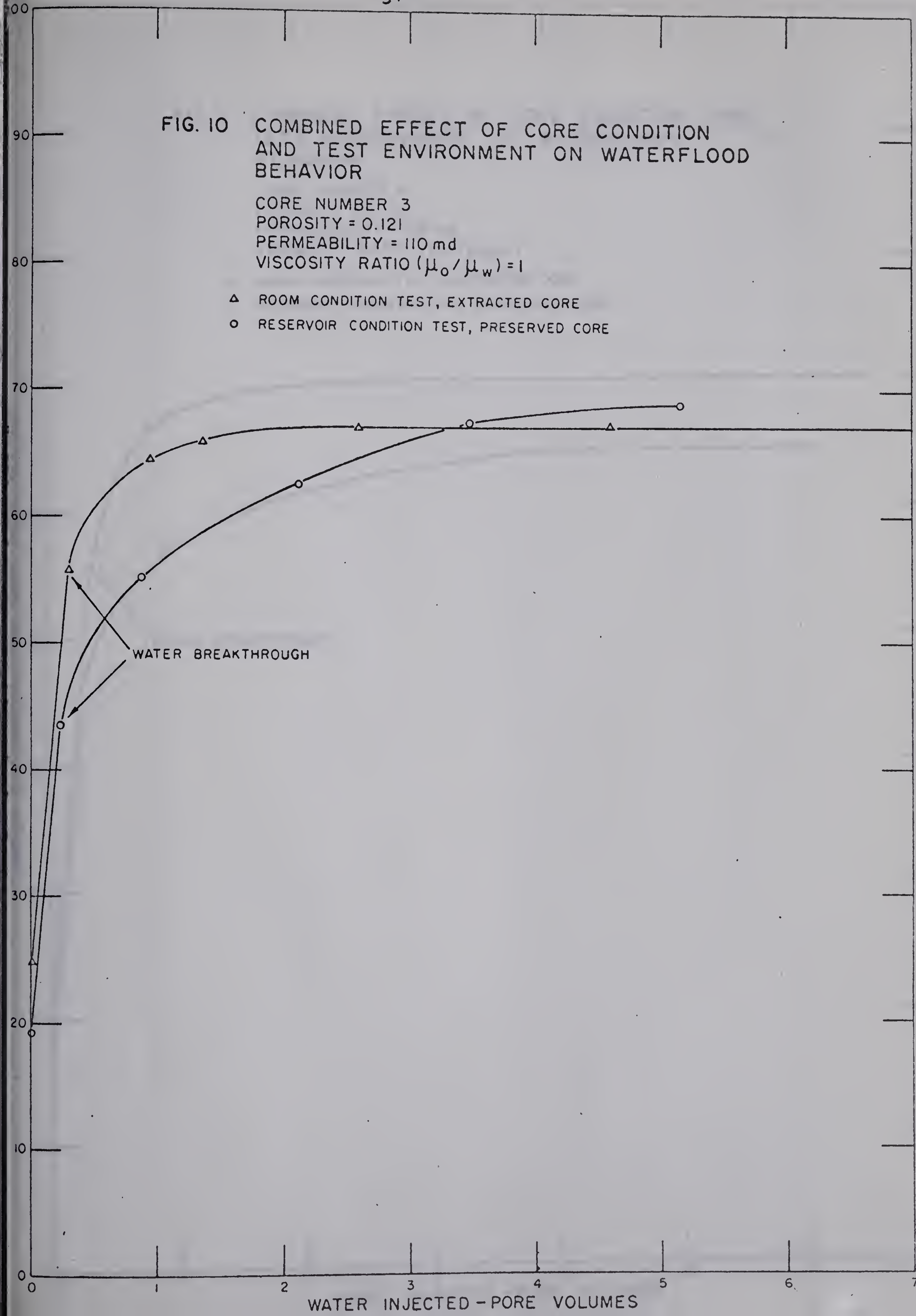


FIG. 10 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON WATERFLOOD BEHAVIOR
CORE NUMBER 3
POROSITY = 0.121
PERMEABILITY = 110 md
VISCOSITY RATIO (μ_o / μ_w) = 1
△ ROOM CONDITION TEST, EXTRACTED CORE
○ RESERVOIR CONDITION TEST, PRESERVED CORE
WATER BREAKTHROUGH
100
90
80
70
60
50
40
30
20
10
0
0
1
2
3
4
5
6
7
WATER INJECTED - PORE VOLUMES

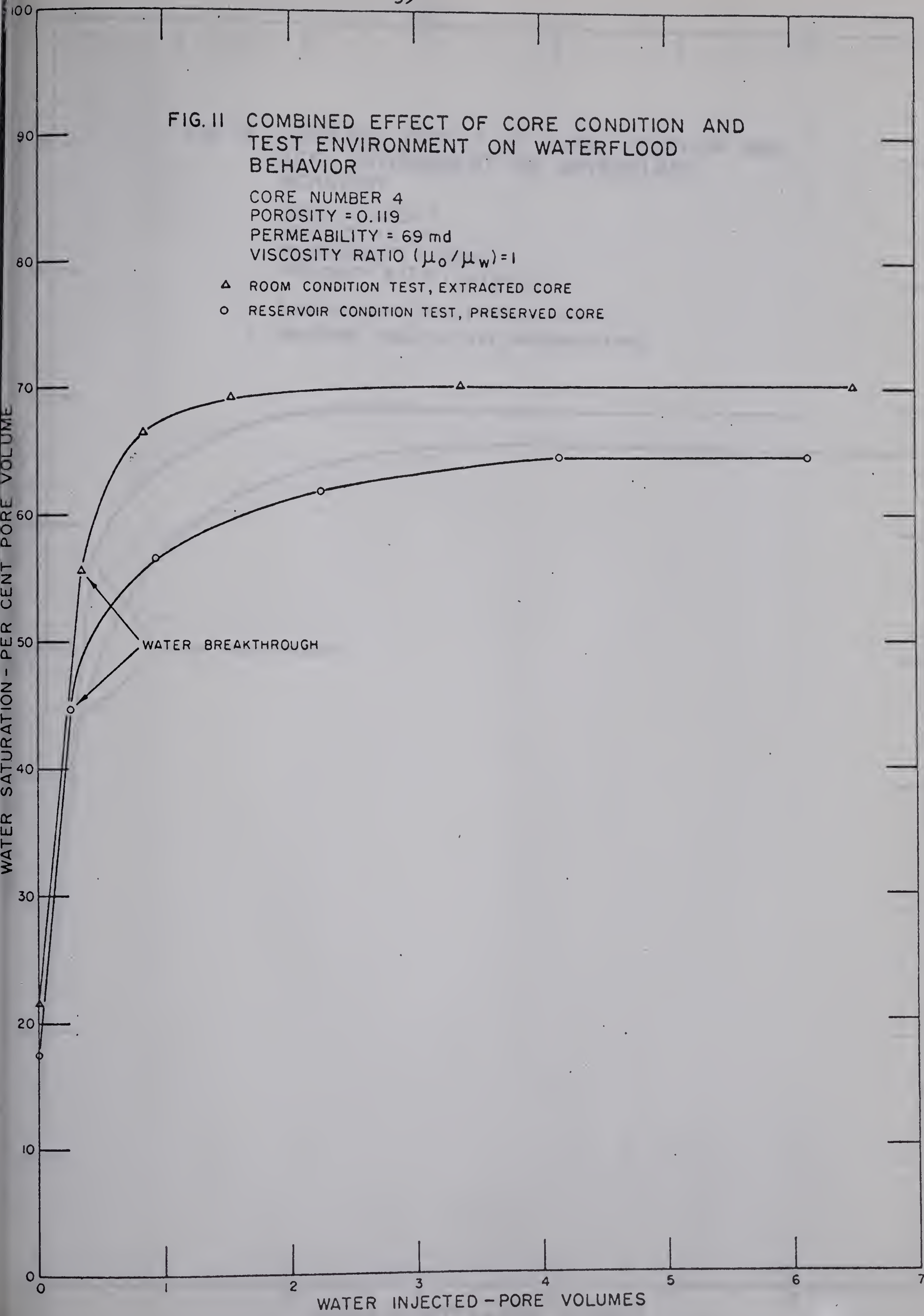


FIG. 11 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON WATERFLOOD BEHAVIOR
CORE NUMBER 4
POROSITY = 0.119
PERMEABILITY = 69 md
VISCOSITY RATIO (μ_o/μ_w) = 1
△ ROOM CONDITION TEST, EXTRACTED CORE
○ RESERVOIR CONDITION TEST, PRESERVED CORE
WATER BREAKTHROUGH
WATER SATURATION - PER CENT PORE VOLUME
WATER INJECTED - PORE VOLUMES
0
10
20
30
40
50
60
70
80
90
100
1
2
3
4
5
6
7

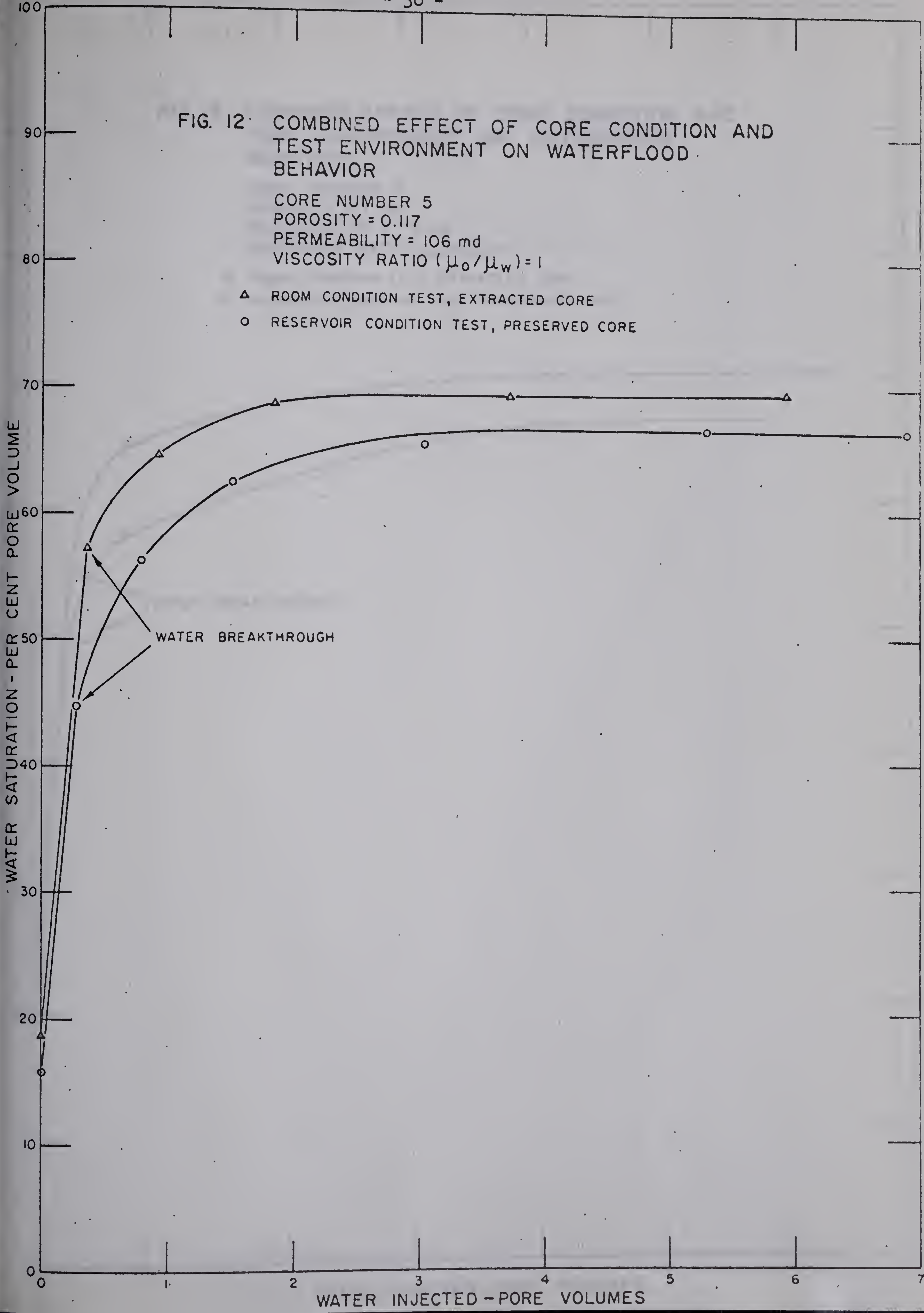


FIG. 12 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON WATERFLOOD BEHAVIOR

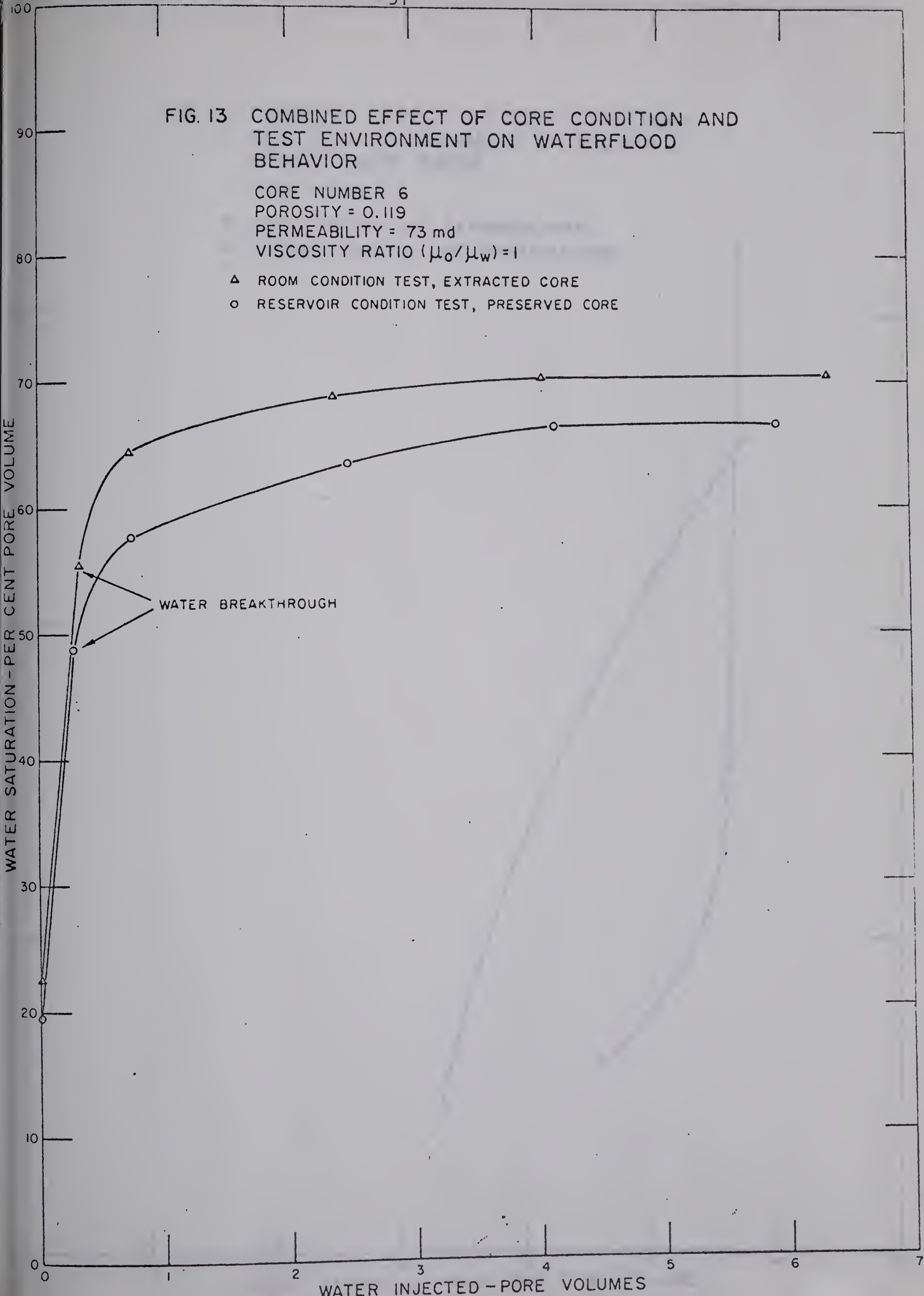


FIG. 13 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON WATERFLOOD BEHAVIOR
CORE NUMBER 6
POROSITY = 0.119
PERMEABILITY = 73 md
VISCOSITY RATIO (μ_o/μ_w) = 1
△ ROOM CONDITION TEST, EXTRACTED CORE
○ RESERVOIR CONDITION TEST, PRESERVED CORE
WATER BREAKTHROUGH
WATER SATURATION - PER CENT PORE VOLUME
WATER INJECTED - PORE VOLUMES
0
10
20
30
40
50
60
70
80
90
100
0
1
2
3
4
5
6
7

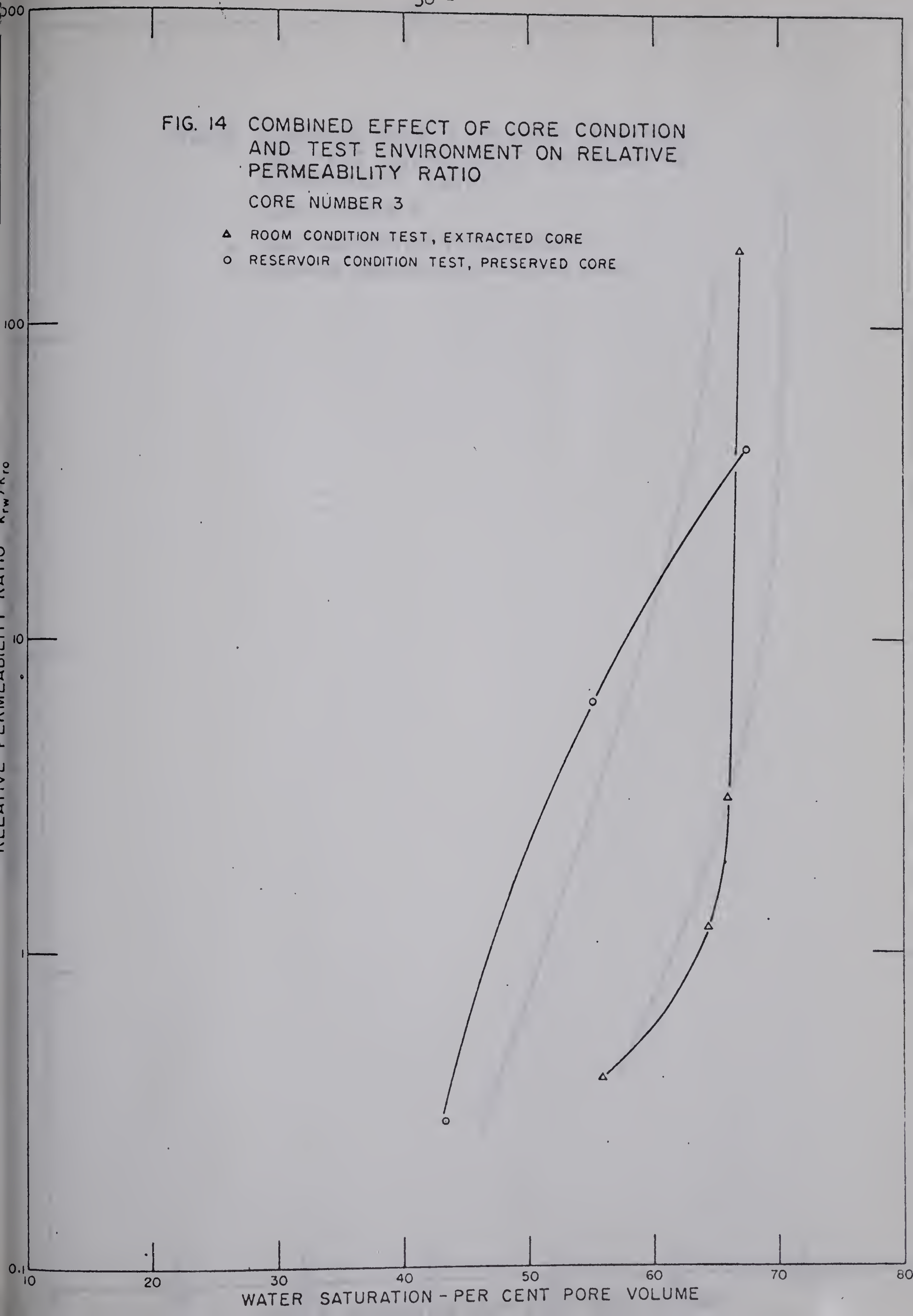


FIG. 14 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON RELATIVE PERMEABILITY RATIO
CORE NUMBER 3
△ ROOM CONDITION TEST, EXTRACTED CORE
○ RESERVOIR CONDITION TEST, PRESERVED CORE
100
10
1
0.1
10
20
30
40
50
60
70
80
WATER SATURATION - PER CENT PORE VOLUME

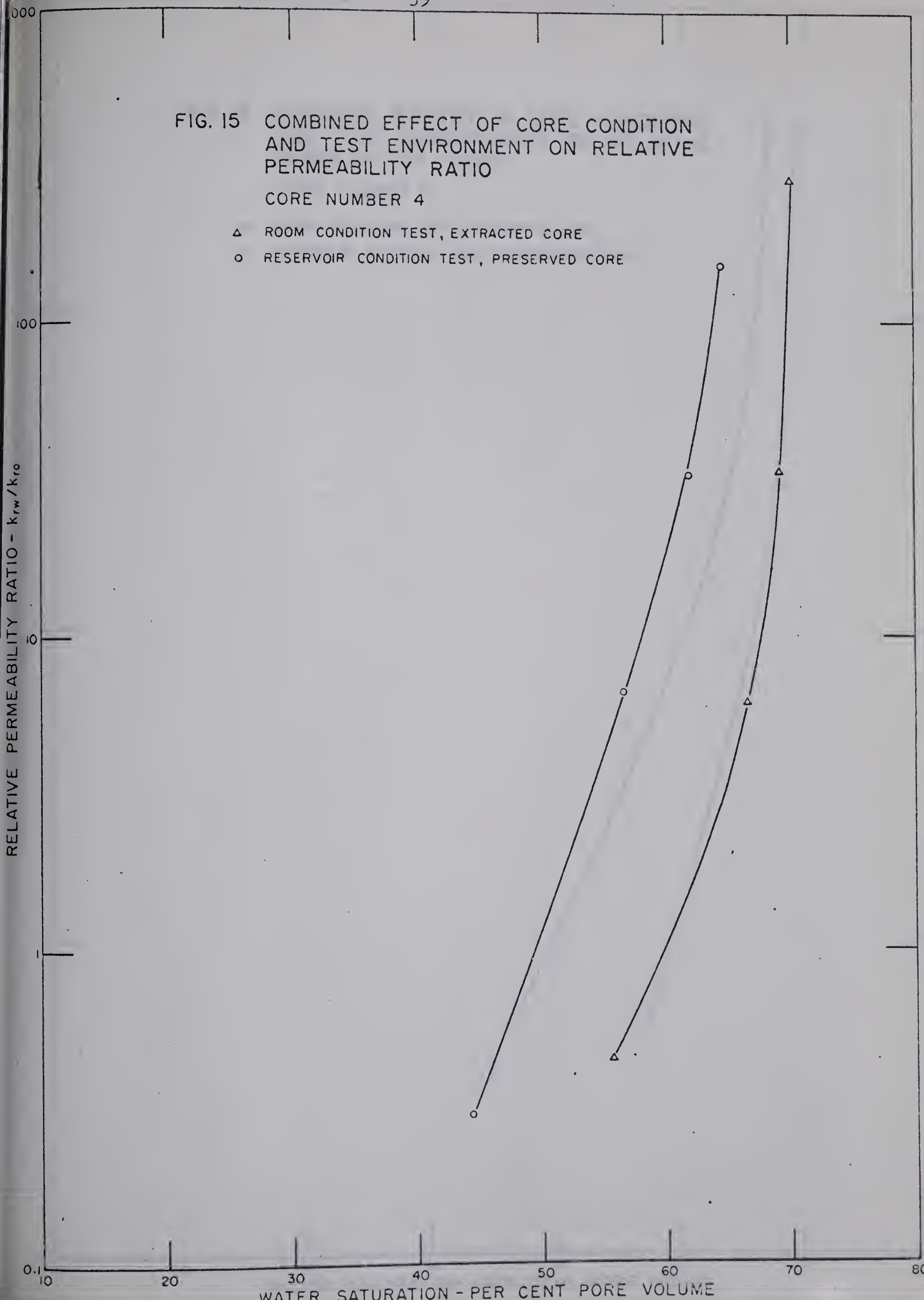


FIG. 15 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON RELATIVE PERMEABILITY RATIO
CORE NUMBER 4
ROOM CONDITION TEST, EXTRACTED CORE
RESERVOIR CONDITION TEST, PRESERVED CORE
RELATIVE PERMEABILITY RATIO - k_{rw}/k_{ro}
WATER SATURATION - PER CENT PORE VOLUME
1000
100
10
1
0.1
10
20
30
40
50
60
70
80

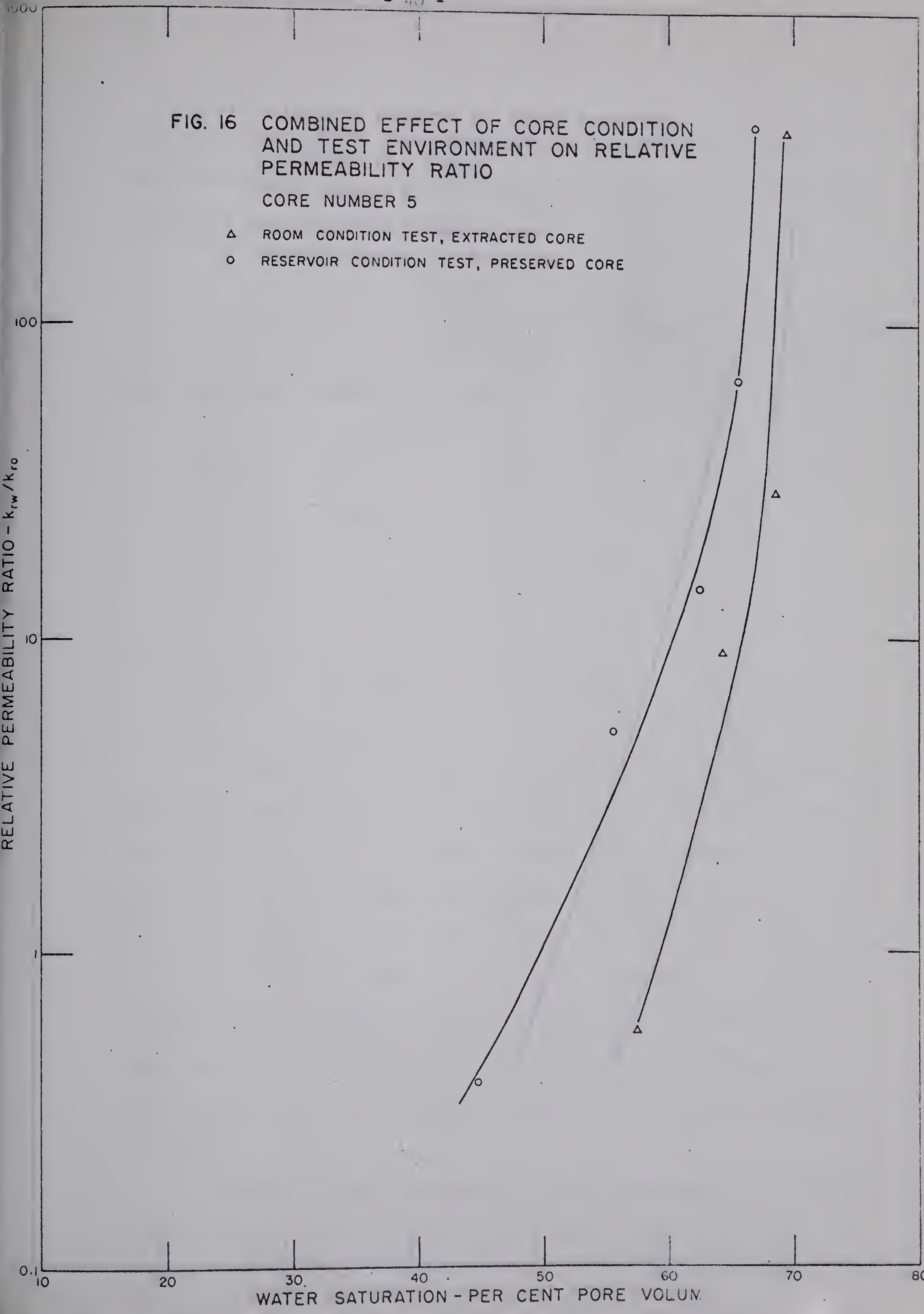


FIG. 16 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON RELATIVE PERMEABILITY RATIO
CORE NUMBER 5
△ ROOM CONDITION TEST, EXTRACTED CORE
○ RESERVOIR CONDITION TEST, PRESERVED CORE
RELATIVE PERMEABILITY RATIO - k_{rw}/k_{ro}
1000
100
10
1
0.1
10
20
30
40
50
60
70
80
WATER SATURATION - PER CENT PORE VOLUM

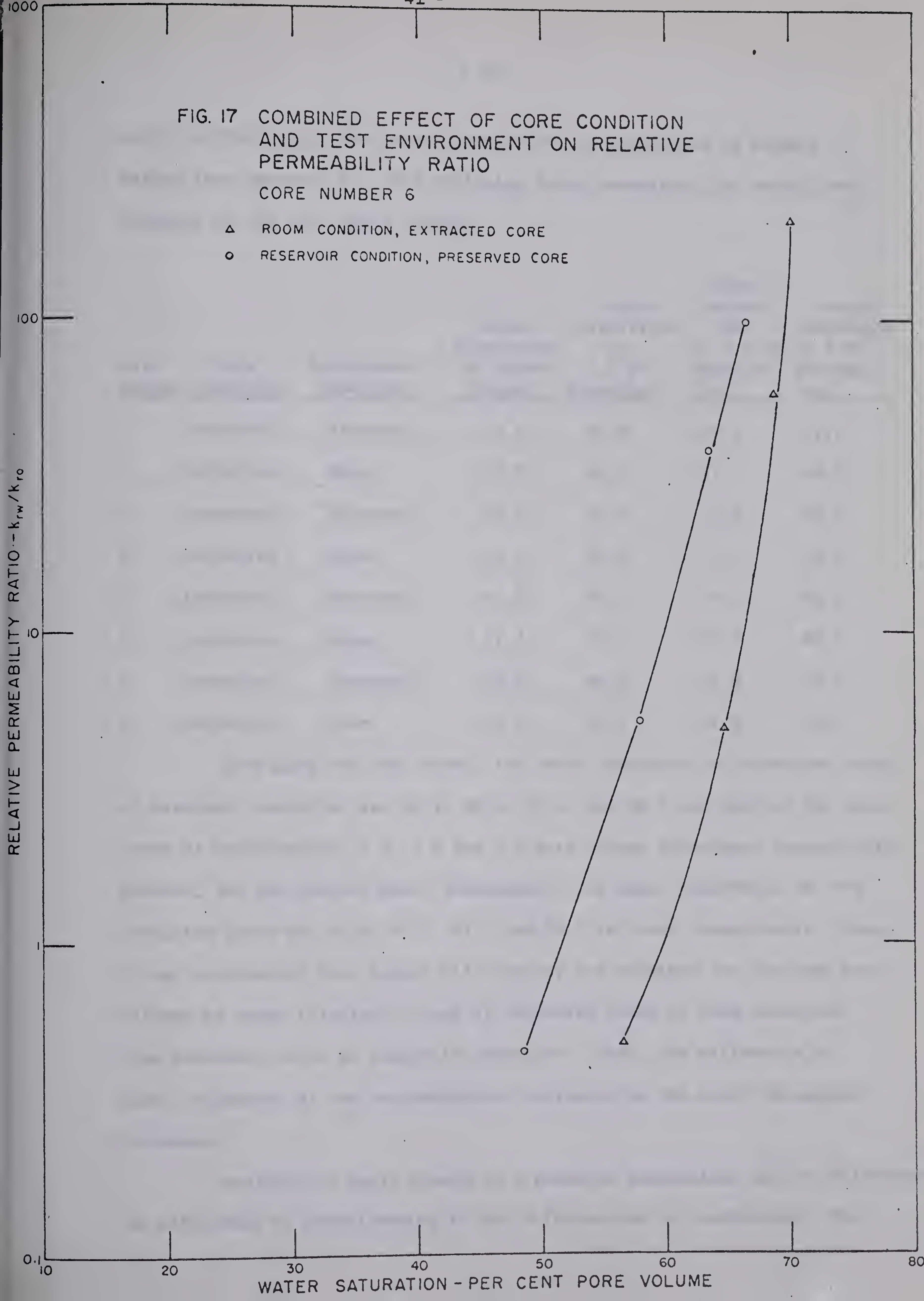
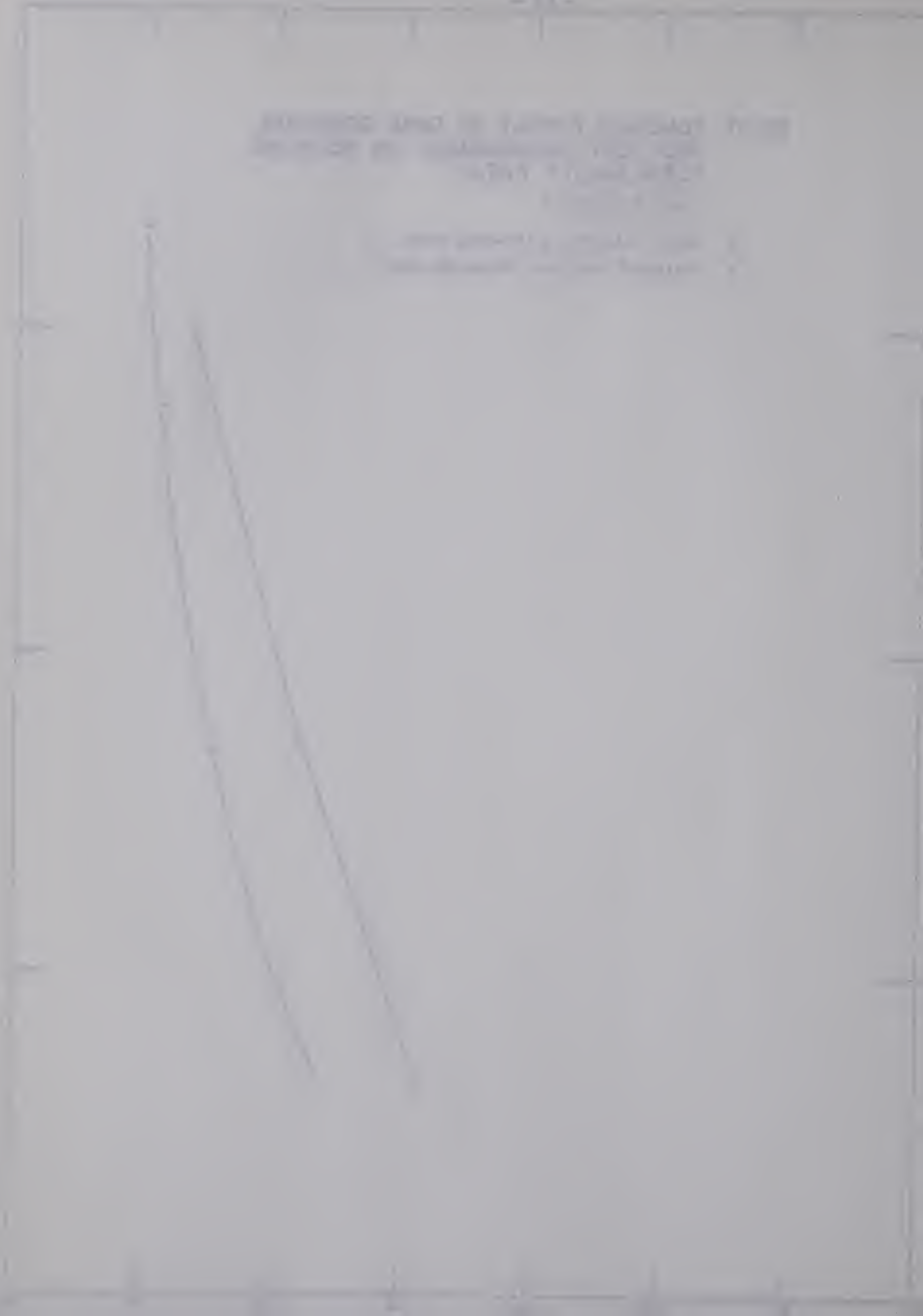


FIG. 17 COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT ON RELATIVE PERMEABILITY RATIO
CORE NUMBER 6



water saturation for the cores three to six as calculated by Welge's Method (see appendix B). The following table summarizes the waterflood behavior of the four cores tested:

Core Number	Core Condition	Environment Condition	Water Saturation at Break-Through	Water Saturation at 1.5 PV Throughput	Water Satura-tion at 3.0 PV Through-Put	Water Saturation at 5 PV Through-Put
3	Preserved	Reservoir	43.6	59.8	66.0	67.1
3	Extracted	Room	55.9	66.3	67.1	68.9
4	Preserved	Reservoir	44.6	59.5	63.2	64.5
4	Extracted	Room	55.7	69.0	70.1	70.2
5	Preserved	Reservoir	44.8	62.3	66.2	66.8
5	Extracted	Room	57.3	67.6	69.3	69.5
6	Preserved	Reservoir	48.6	60.8	64.8	67.5
6	Extracted	Room	56.5	67.0	69.8	70.3

Averaging the four cores, the water saturation of preserved cores at reservoir condition was 45.4, 60.6, 65.1, and 66.5 per cent of the pore space at breakthrough, 1.5, 3.0 and 5.0 pore volume throughput respectively. However, for the similar water throughputs, the water saturation for the extracted cores was 56.4, 67.5, 69.1 and 69.7 per cent respectively. Hence, it may be observed that higher oil recovery was obtained for the same pore volumes of water injected in case of extracted cores at room condition, than preserved cores at reservoir condition. Also, the difference in water saturation at the two conditions decreases as the water throughput increases.

Wettability again stands as a probable explanation for the difference in efficiency of waterflooding in two different set of conditions. The

shapes of performance curves suggest that the preserved cores at reservoir condition were relatively less water-wet than the extracted cores at room condition. This is also confirmed by krw/kro versus saturation curves.

In the various tests conducted in this work the initial saturation varied from 0.105 to 0.248. Although it was realized that the initial water saturation affects waterflood performance, the test procedure used in this work did not allow for the control of this variable.

The accuracy of the test results was very dependent upon the measurement of the volume of oil produced. For example for the size of core used in this work, an error of 0.1 ccs. in the measurement of oil volume would produce an error of approximately 1.5 oil saturation percent. In order that the calculated saturation be correct to $\pm$ 1.0 percent, oil production was determined gravimetrically.

Although povosity and permeability values were obtained during the run an independent check was made using standard techniques.

Effect of Test Environment

The effect of test environment alone may be deduced indirectly from the results of this work. The following table compares the average waterflood behavior of four reservoir condition tests using preserved cores and reservoir oil, six room condition tests using extracted cores and refined oil, and 2 room condition tests using preserved cores and refined oil:

Water Saturation	Reservoir Condition Preserved Core (4 Runs)	Room Condition Preserved Core (2 Runs)	Room Condition Extracted Core (6 Runs)
At Breakthrough	45.4	46.1	57.8
At 1.5 Pore Volume of water injected	60.6	60.9	68.2
At 3.0 Pore Volume of water injected	65.1	65.8	69.3

It seems that the waterflood behavior of preserved cores at reservoir conditions is in very good agreement with the waterflood behavior of preserved cores at room condition, whereas both differ considerably from waterflood behavior of extracted cores at room condition. A similar conclusion may be reached by examination of Figure 18, which shows the ratio of relative permeabilities (krw/kro) versus saturation for all the cases mentioned above.

Hence, it might be inferred that the test environments (i.e. use of high temperature, high pressure and reservoir oil) have a negligible effect; whereas, the core condition has a very definite effect on the waterflood behavior of the particular rock-crude oil system under investigation.

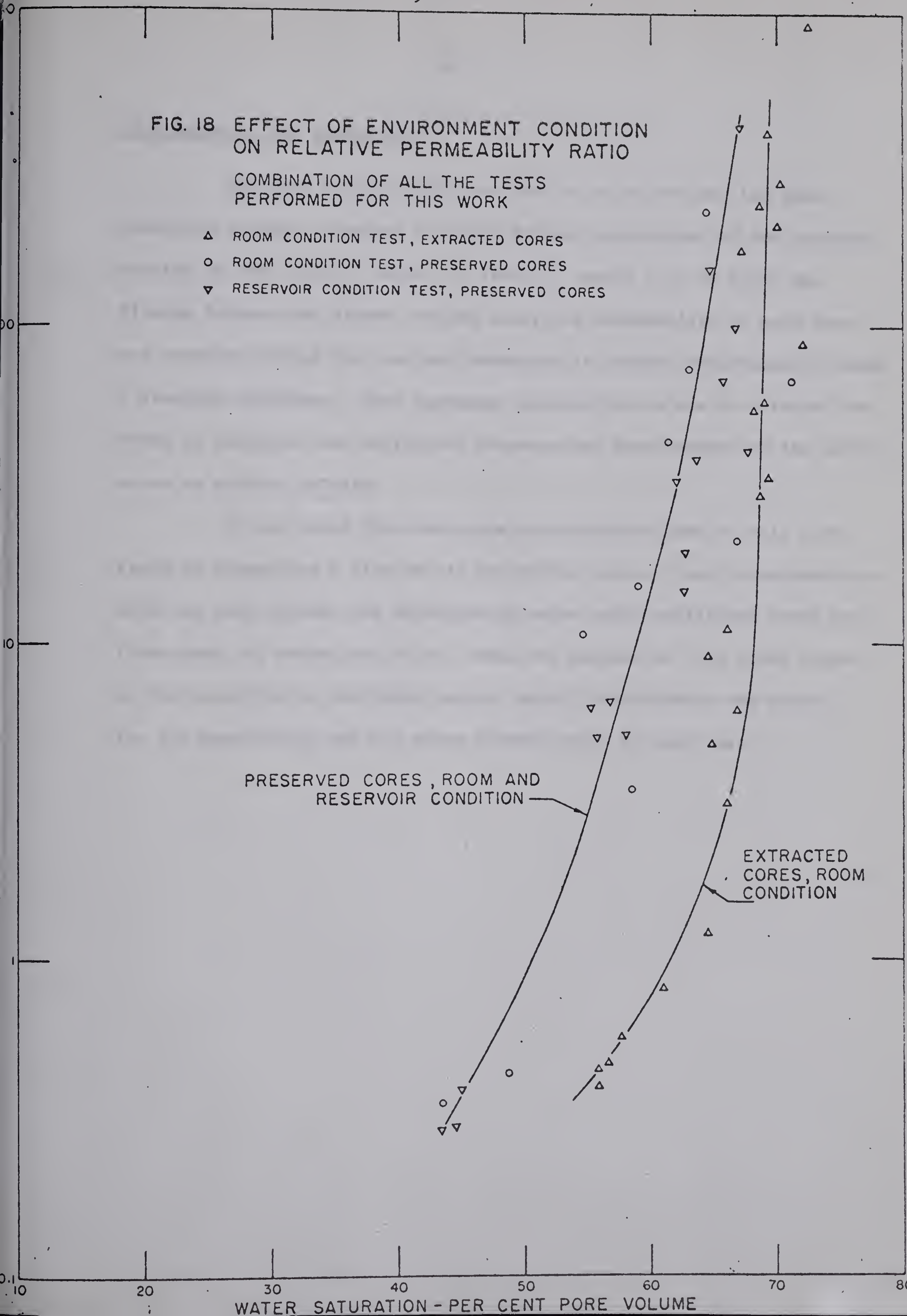


FIG. 18 EFFECT OF ENVIRONMENT CONDITION ON RELATIVE PERMEABILITY RATIO
COMBINATION OF ALL THE TESTS PERFORMED FOR THIS WORK
△ ROOM CONDITION TEST, EXTRACTED CORES
○ ROOM CONDITION TEST, PRESERVED CORES
▽ RESERVOIR CONDITION TEST, PRESERVED CORES
PRESERVED CORES, ROOM AND RESERVOIR CONDITION
EXTRACTED CORES, ROOM CONDITION
100
10
1
0.1
10
20
30
40
50
60
70
80
WATER SATURATION - PER CENT PORE VOLUME

Discussion of the Equipment

The core holder, which was used in this work and has been described earlier, provided no means for the measurement of the pressure exerted on the sleeve. Hence, in order to assure that no fluid was flowing between the sleeve and the core, the permeability of each core was measured during the run, and subsequently checked independently using a standard technique. Good agreement between the values so obtained was taken to indicate that sufficient pressure had been exerted on the sleeve, so as to prevent by-pass.

It was found that the probe type detector used in this work, tends to accumulate a film of oil around the probe. Such an accumulation would in turn prevent the detection of water until sufficient water had flown past, to remove the film. Since the success of this study hinged on the detection of the first drop of water, the detector was tested for its sensitivity and the probe cleaned prior to each test.

CONCLUSIONS

The following conclusions may be made as a result of this experimental investigation into waterflooding at simulated reservoir conditions.

1. It is not possible in general to establish the waterflood behavior of a preserved rock sample at reservoir conditions by observing the flooding performance of the extracted sample at room conditions.
2. For the particular rock crude oil system used for this work, the waterflood recovery of preserved cores at reservoir conditions was less than that of extracted cores at room conditions.
3. For the particular rock crude oil system used for this work, the waterflood recovery of preserved cores at room condition was less than that of extracted cores at room condition.
4. For the cores tested it was observed that the average recovery of a preserved core at room conditions may be representative of the recovery obtainable from a preserved core at reservoir conditions.
5. Temperature and pressure seem to have little influence on the waterflood behavior of the samples studied.
6. Additional research is needed to isolate the individual effects of temperature, pressure, and fluid composition on wettability and displacement behavior of reservoir rocks.

NOMENCLATURE

English

A = cross sectional area of core (cm^2)

f = fraction of flow stream consisting of a particular phase

g = acceleration of gravity ($cm/sec.^2$)

k = absolute permeability (md.)

kr = relative permeability (md.)

L = length of core (cm.)

Pc = capillary pressure (dynes/cm)

Qi = cumulative water injected (c.c.)

q = total flow rate (c.c./sec.)

r = radius of capillary (cm.)

s = saturation (fraction)

t = time (sec.)

x = distance travelled by a constant saturation front (cm.)

Greek

ρ = density (gms/c.c.)

σ = interfacial or surface tension (dynes/cm.)

θ = contact angle

μ = viscosity (c.p.)

ϕ = porosity (fraction)

α = angle from horizontal

Subscripts

D = displacing fluid

o = oil phase

w = water

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A P P E N D I X   A

FORMATION WATER ANALYSIS

TABLE A
ANALYSIS OF RESERVOIR WATER

Component	Mg per litre	Per Cent Calculated Solids
Na & K	51,400	47.31
Ca	1,986	2.10
Mg	340	0.59
Fe	Present	
SO_4	100	0.04
Cl	83,200	49.65
CO_3		
HCO_3	893	0.31
OH		
H_2S	Present	
Total Solids	137,919	100.00

Specific Gravity	1.087
pH	6.1
Resistivity, ohm meters @ 68°F	0.072
Total Solids	
By Evaporation	144,220 ppm
After Ignition	124,960 ppm

APPENDIX B

WELGE'S METHOD

CALCULATION OF RELATIVE PERMEABILITY RATIO WELGE'S METHOD

Equation (13) of the reference by Leverett (33) which gives the fractional flow of displacing fluid in the total flowing stream, may be written.

$$f_D = \frac{1 - \frac{k_o}{\mu_o\, q(t)} \frac{\partial Pc}{\partial x} + g\,\Delta\rho \sin\alpha}{1 + \frac{k_o}{k_D}\frac{\mu_D}{\mu_o}} \qquad \text{(B-1)}$$

Welge (34) has shown that capillary forces may generally be neglected, and in this particular work, the displacement tests were always conducted on horizontal cores, hence, for this case gravity terms may also be neglected. Thus, equation (B-1) may be written as:

$$f_D = \frac{1}{1 + \frac{k_o}{k_D}\frac{\mu_D}{\mu_o}} \qquad \text{(B-2)}$$

also $$f_D + f_o = 1 \qquad \text{(B-3)}$$

Combining equations (B-2) and (B-3), we get:

$$f_o = \frac{\frac{k_o}{k_D}\frac{\mu_D}{\mu_o}}{1 + \frac{k_o}{k_D}\frac{\mu_D}{\mu_o}} \qquad \text{(B-4)}$$

rearranging,

$$\frac{k_D}{k_o} = \frac{k - f_o}{\frac{\mu_o}{\mu_D} f_o} \qquad \text{(B-5)}$$

Buckley & leverett (1) have expressed material balance over a thin section of the reservoir, for a linear system with incompressible fluids, which may be written in the form:

$$v \frac{\partial f_o}{\partial x} + \frac{\partial s}{\partial t} = 0 \qquad \text{(B-6)}$$

where $v = \frac{u(t)}{\emptyset}$; $u(t) = \frac{q(t)}{A}$

Since f_D by equation (B-1) is a function of s only (through ko and k_g), we may write for the first derivative in equation (B-6),

$$\frac{\partial f_D}{\partial x} = \frac{df_D}{ds}\frac{\partial s}{\partial x} \tag{B-7}$$

in which the total derivative df_D/ds may be obtained from equation (B-1). After substituting (B-7) into (B-6) equation (B-6) can be rearranged and partially solved by standard method to give the relation:

$$\left(\frac{\Delta x}{\Delta t}\right)_s = \left(\frac{dx}{dt}\right)_s = -\frac{\frac{\partial s}{\partial t}}{\frac{\partial s}{\partial x}} = \frac{vdf_D}{ds} = v\ f'_D \tag{B-8}$$

where $f'_D = \dfrac{df_D}{ds}$

Equation (B-8) gives the distance traveled by the various gas saturations in any given time, t. The distance traveled, x, is proportional to the f'_D function, the constant of proportionality being t. A further relationship may be derived from equation (B-8) by applying it to the outlet face of the core when x = L:

$$\frac{1}{f'_D} = \frac{1}{f_D(s)} = \frac{v\ \Delta t}{L} = Qi \tag{B-9}$$

where $\quad x = L\text{-}o$

and $\quad Q_i$ = Cumulative injection in pore volumes at the time the saturation (s) reach the outflow face.

The average saturation of the porous media, Savg, may be evaluated:

$$\text{Savg} = \frac{\int_1^2 S\ dx}{X2} \tag{B-10}$$

where the limits 1 and 2 refer to the inlet and outlet ends of the system. Since x is proportional to f'_D,

$$\text{Savg} = \frac{\int_1^2 S\ dx}{f'_{D2}} \tag{B-11}$$

The integration of equation (B-11) by parts:

$$S_{avg} = \frac{S_2\, f'_{D2} - \int_1^2 f'_D\, ds}{f'_{D2}}$$

$$= \frac{S_2\, f'_{D2} - \int_1^2 df_D}{f'_{D2}}$$

$$= S_2 - \frac{f_{D2} - f_{D1}}{f'_{D2}}$$

Since $f_{D1} = 1.0$ and using equation (B-9)

$$S_{avg} = S_2 - (f_{D2} - 1.0)\, Q_i \tag{B-12}$$

$$S_{avg} - S_2 = f_{o2}\, Q_i \tag{B-13}$$

$$\text{where } f_{o2} + f_{D2} = 1.0 \tag{B-14}$$

The evaluation of $f_{o2}\, Q_i$ in equation (B-13) gives the difference between the average displacing fluid saturation and the saturation at outflow terminal.

Differentiating equation (B-12) with respect to Qi =

$$\frac{dS_{avg}}{dQ_i} = \frac{dS_2}{dQ_i} - (f_{D2} - 1.0) - Q_i\, \frac{df_{D2}}{dQ_i} \tag{B-15}$$

Using equations (B-14) and (B-9):

$$\frac{dS_{avg}}{dQ_i} = f_{o2} + \frac{dS_2}{dQ_i} - \frac{dS_2}{df_{D2}}\,\frac{df_{D2}}{dQ_i} \tag{B-16}$$

or

$$\frac{dS_{avg}}{dQ_i} = f_{o2} \tag{B-17}$$

A computer program, which is included in Appendix C, was written to calculate k_D/k_o. This program makes use of equations (B-17) and (B-5). Water was used as the displacing fluid throughout this work; hence,

$$\frac{k_D}{k_o} = \frac{k_w}{k_o} = \frac{k_{rw}}{k_{ro}} \tag{B-18}$$

A P P E N D I X C

THE COMPUTER PROGRAM FOR RELATIVE PERMEABILITY RATIO (krw/kro) CALCULATION

C-1. FORTRAN SOURCE LISTS

```
/+
C                         WATER-OIL RELATIVE PERMEABILITY
C
C
C
      DIMENSION LSN(2),TIME(200),PI(200),CO(200),CW(200),A250(200),
     1          A300(200),A350(200),A400(200),IDENT(20),A100(200),
     2          A750(200),A450(200)
      EQUIVALENCE (CW(1),A100(1))
      IN=1
      IO=3
 5000 READ (IN,1) IDENT
    1 FORMAT(20A4)
 6000 READ (IN,10) PV,WS,WV,OV,AS,SL,WK,N,LSN
   10 FORMAT(F5.3,2F4.3,3F5.2,F6.2,I3,2A4)
      IF (PV) 5000,5000,7000
 7000 IF (PV-900.) 8000,8000,9000
 8000 READ (IN,20) (TIME(I),I=1,N)
   20 FORMAT(16F5.0)
      READ (IN,20) (PI(I),I=1,N)
      READ (IN,25) (CO(I),I=1,N)
   25 FORMAT(16F5.3)
   30 FORMAT(16F5.2)
      READ (IN,30) (CW(I),I=1,N)
      WRITE (IO,100) IDENT,LSN
  100 FORMAT(32H1WATER-OIL RELATIVE PERMEABILITY,18X,20A4//
     1      1H0,16X,28HLAB SAMPLE IDENTIFICATION - ,2A4//)
      WRITE (IO,200) PV,AS,WS,SL,WV,WK,OV
  200 FORMAT(14H0PORE VOLUME =,F6.3,5H C.C.,25X,16HAREA OF SAMPLE =,
     1      F6.2,7H SQ.CM./27H0INITIAL WATER SATURATION =,F6.3,
     2      9H FRACTION,8X,18HLENGTH OF SAMPLE =,F6.2,4H CM./18H0WATER
     3 VISCOSITY =,F5.3,4H CP.,23X,20HWATER PERMEABILITY =,F7.2,4H MD./
     4      16H0OIL VISCOSITY =,F6.2,4H CP.//
     5      26H0INPUT TABLES - TIME (SEC)/)
      WRITE (IO,300) (TIME(I),I=1,N)
  300 FORMAT(10F9.0)
      WRITE (IO,400)
  400 FORMAT(1H0,13X,27H- INJECTION PRESSURE (PSIG))
      WRITE (IO,300) (PI(I),I=1,N)
      WRITE (IO,500)
  500 FORMAT(1H0,13X,32H- CUMULATIVE OIL PRODUCED (C.C.))
      WRITE (IO,600) (CO(I),I=1,N)
  600 FORMAT(10F9.3)
      WRITE (IO,700)
  700 FORMAT(1H0,13X,34H- CUMULATIVE WATER PRODUCED (C.C.))
      WRITE (IO,600) (CW(I),I=1,N)
      WRITE (IO,800)
```

```
00 FORMAT(90H1   TIME     CUM VOL QW         SW      REL PERM    SW(2)      KO
  1      KW         KOK         KWK         /
  2         90H  (SEC.)      (P.V.)         (AVG.)  (KW/KO)                 (MD)
  3     (MD)                                /)
   NMO=N-1
   NMT=N-2
   DO 1000 I=1,N
   CO(I)=CO(I)/PV
   CW(I)=CW(I)/PV
   A250(I)=CO(I)+CW(I)
00 A300(I)=CO(I)+WS
   DO 1010 I=1,NMT
   X=((A300(I)-A300(I+1))/(A250(I)-A250(I+1))-(A300(I)-A300(I+2))
  1      /(A250(I)-A250(I+2)))/(A250(I+1)-A250(I+2))
10 CO(I+1)=2.*X*A250(I+1)+((A300(I)-A300(I+1))/(A250(I)-A250(I+1))
  1          -X*(A250(I)+A250(I+1)))
   CO(1)=CO(2)
   CO(N)=CO(NMO)
   WOO=WV/OV
   DO 1015 I=1,N
   A350(I)=WOO/CO(I)*(1.-CO(I))
   A400(I)=A300(I)-CO(I)*A250(I)
15 CONTINUE
   DO 1020 I=1,NMT
20 A100(I+1)=A250(I)*(TIME(I+1)-TIME(I+2))/((TIME(I)-TIME(I+2))
  1             *(TIME(I)-TIME(I+1)))+A250(I+1)*(2.*TIME(I+1)-TIME(I)-
  2             TIME(I+2))/((TIME(I+1)-TIME(I+2))*(TIME(I+1)-TIME(I)))
  3             +A250(I+2)*(TIME(I+1)-TIME(I))/((TIME(I+2)-TIME(I+1))
  4             *(TIME(I+2)-TIME(I)))
   A100(1)=A100(2)
   A100(N)=A100(NMO)
   PVA=PV/AS
   DO 1030 I=1,N
   X=PVA*CW(I)
   Y=PI(I)/14.69/X
   CW(I)=1./A250(I)
30 PI(I)=CW(I)*Y
   FN=N
   DO 1040 I=1,NMT
   X=CW(I)*PI(I)+CW(I+1)*PI(I+1)+CW(I+2)*PI(I+2)
   Y=(CW(I)+CW(I+1)+CW(I+2))*(PI(I)+PI(I+1)+PI(I+2))/FN
   Y=X-Y
   Z=CW(I)*CW(I)+CW(I+1)*CW(I+1)+CW(I+2)*CW(I+2)
40 A750(I+1)=Y/(Z-(CW(I)+CW(I+1)+CW(I+2))**2/FN
   A750(1)=A750(2)
   A750(N)=A750(NMO)
```

```
      OVL=OV*SL
      DO 1050 I=1,N
      PI(I)=CO(I)*OVL/A750(I)*1000.
      CO(I)=PI(I)*A350(I)
      CW(I)=PI(I)/WK
   50 A450(I)=CO(I)/WK  .
      DO 2000 I=1,N
      ITM=TIMF(I)
   00 WRITE (IO,2100) ITM,A250(I),A300(I),A350(I),A400(I),PI(I),
     1                CO(I),CW(I),A450(I)
   00 FORMAT(I6,2F11.3,F10.3,F8.3,4F9.3)
      GO TO 6000
   00 STOP 124
      END
```

C-2. NOMENCLATURE OF COMPUTER INPUT

AS	Cross sectional area of the sample (sq. cm.)
CO	Cumulative oil production (c.c.)
CW	Cumulative water production (c.c.)
LSN	Sample's laboratory identification (alpha-numeric)
N	Number of values/table
OV	Oil viscosity (cp.)
PI	Injection pressure (psia)
SL	Length of the sample (cm.)
PV	Pore volume of the sample (c.c.)
WK	Absolute permeability of the sample to water (md.)
WS	Initial water saturation of the sample (fraction of pore volume)
WV	Water viscosity (cp.)

A P P E N D I X D

THE TEST RESULTS

TABLE D-1

STUDY OF EFFECT OF CORE CONDITION

CORE NUMBER 1

Core Description

Visual: Fine grained, vuggy, light grey, conquinoidal dolostone

Properties:
Porosity = 0.121
Absolute Permeability to water = 78 md.
Length of the sample = 8.21 cm.
Area of the sample = 7.91 sq. cm.

Extracted Core

Pore Volume = 7.83 c.c.
Initial water saturation = 0.108
Scaling coefficient = 5.66 cm^2cp/min.

Oil viscosity = 1.18 cp
Water viscosity = 1.04 c.p.
Injection Rate = 40 c.c./hr.

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.108	
0.497	0.605	0.815
0.739	0.685	2.381
2.619	0.720	87.589
4.872	0.726	913.489
6.287	0.726	

Preserved Core

Pore Volume = 7.87 c.c.
Initial water saturation = 0.114
Scaling coefficient = 5.66 cm^2cp/min.

Oil viscosity = 1.8 cp
Water viscosity = 1.04 c.p.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.114	
0.321	0.435	0.360
0.900	0.585	3.987
2.269	0.669	21.165
4.266	0.712	67.168
6.576	0.728	

TABLE D-2

STUDY OF EFFECT OF CORE CONDITION

CORE NUMBER 2

Core Description

Visual: Fine to medium grained, vuggy, brown, coquinoidal dolostone

Properties: Porosity = 0.118
Absolute Permeability to water = 92 md.
Length of the sample = 7.12 cm.
Area of the sample = 7.91 sq. cm.

Extracted Core

Pore Volume = 6.35 c.c.
Initial water saturation = 0.142
Scaling coefficient = 4.91 cm^2cp/min.

Oil viscosity = 1.18 cp
Water viscosity = 1.04 cp.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.142	
0.468	0.610	0.817
0.921	0.662	11.574
1.578	0.681	50.536
2.402	0.687	240.760
3.372	0.687	
4.702	0.687	

Preserved Core

Pore Volume = 6.89 c.c.
Initial water saturation = 0.105
Scaling coefficient = 4.91 cm^2cp/min.

Oil viscosity = 1.18 cp
Water viscosity = 1.04 cp.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.105	0.471
0.382	0.487	0.471
1.090	0.548	10.835
1.612	0.591	15.134
2.453	0.614	43.088
3.512	0.632	73.435
5.179	0.646	229.506
6.832	0.646	

TABLE D-3

STUDY OF COMBINED EFFECT OF CORE CONDITION
AND TEST ENVIRONMENT
CORE NUMBER 3

Core Description

Visual: Fine grained, light-grey, vuggy, coquinoidal dolostone.

Properties: Porosity = 0.121
Absolute Permeability to water = 110 md.
Length of the sample = 7.98 cm.
Area of the sample = 7.91 sq. cm.

Room Condition Test

Pore Volume = 7.63 c.c.
Initial water saturation = 0.248
Scaling coefficient = 5.51 $cm^2 \cdot cp/min$.

Oil viscosity = 1.18 cp.
Water viscosity = 1.04 cp.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.248	
0.311	0.559	0.399
0.942	0.644	12.094
1.371	0.660	32.673
2.603	0.671	167.696
4.606	0.671	

Reservoir Condition Test

Pore Volume = 7.65 c.c.
Initial water saturation = 0.192
Scaling coefficient = 5.05 $cm^2 \cdot cp/min$.

Oil viscosity = 0.43 cp.
Water viscosity = 0.38 cp.
Injection Rate = 100 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.192	
0.244	0.436	0.291
0.892	0.551	6.279
2.122	0.626	19.383
3.493	0.676	41.754
5.148	0.689	

TABLE D-4

STUDY OF COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT CORE NUMBER 4

Core Description

Visual: Fine to medium grained, vuggy, medium grey, coquinoidal dolostone.

Properties: Porosity = 0.119
Absolute Permeability to water = 69 md.
Length of the sample = 7.35 cm.
Area of the sample = 7.91 sq. cm.

Room Condition Test

Pore Volume = 6.90 c.c.
Initial water saturation = 0.216
Scaling coefficient = 5.04 $cm^2 \cdot cp/min.$

Oil viscosity = 1.18 cp.
Water viscosity = 1.04 cp.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.216	
0.341	0.557	0.459
0.852	0.665	6.250
1.538	0.691	33.242
3.371	0.702	285.550
6.501	0.702	

Reservoir Condition Test

Pore Volume = 6.95 c.c.
Initial water saturation = 0.183
Scaling coefficient = 4.65 $cm^2 \cdot cp/min.$

Oil viscosity = 0.43 cp.
Water viscosity = 0.38 cp.
Injection Rate = 100 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.183	
0.263	0.446	0.300
0.941	0.566	6.700
2.242	0.619	32.852
4.157	0.643	153.303
6.129	0.643	

TABLE D-5

STUDY OF COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT
CORE NUMBER 5

Core Description

Visual: Medium grained, vuggy, light-grey, coquinoidal dolostone.

Properties: Porosity = 0.117
Absolute Permeability to Water = 106 md.
Length of the sample = 7.69 cm.
Area of the sample = 7.91 sq. cm.

Room Condition Test

Pore Volume = 7.12 c.c.
Initial water saturation = 0.185
Scaling coefficient = 5.28 $cm^2 \cdot cp/min$.

Oil viscosity = 1.18 cp.
Water viscosity = 1.04 cp.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.185	
0.388	0.573	0.569
0.931	0.643	9.122
1.853	0.686	29.124
3.735	0.695	411.385
5.958	0.695	411.385

Reservoir Condition Test

Pore Volume = 7.13 c.c.
Initial water saturation = 0.158
Scaling coefficient = 4.87 $cm^2 \cdot cp/min$.

Oil viscosity = 0.43 cp.
Water viscosity = 0.38 cp.
Injection Rate = 100 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.158	
0.290	0.448	0.388
0.812	0.562	5.162
1.527	0.624	14.267
3.056	0.656	66.381
5.317	0.669	430.492
6.921	0.669	

TABLE D-6

STUDY OF COMBINED EFFECT OF CORE CONDITION AND TEST ENVIRONMENT CORE NUMBER 6

Core Description

Visual: Fine grained, brown, vuggy, coquinoidal dolostone.

Properties: Porosity = 0.119
Absolute Permeability to water = 73 md.
Length of the sample = 6.92 cm.
Area of the sample = 7.91 sq. cm.

Room Condition Test

Pore Volume = 6.53 c.c.
Initial water saturation = 0.223
Scaling coefficient = 4.75 $cm^2 \cdot cp/min$.

Oil viscosity = 1.18 cp.
Water viscosity = 1.04 cp.
Injection Rate = 40 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.223	
0.342	0.565	0.574
0.744	0.647	4.895
2.372	0.689	58.039
4.057	0.702	212.186
6.320	0.702	

Reservoir Condition Test

Pore Volume = 6.53 c.c.
Initial water saturation = 0.194
Scaling coefficient = 4.38 cm cp/min.

Oil viscosity = 0.43 cp.
Water viscosity = 0.38 cp.
Injection Rate = 100 c.c./hour

Number of Pore Volume Throughput	Average Water Saturation of the Core	krw/kro
0.0	0.194	
0.292	0.486	0.448
0.760	0.578	5.189
2.482	0.634	38.166
4.152	0.666	99.096
5.949	0.666	

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